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2003 ANNUAL REPORT

Profitability

ON TRACK

Profitable Growth



Highlights

(stated in millions of Canadian dollars, unless otherwise indicated)

	2003	2002	2001
FINANCIAL			
Earnings from operations ^{1,2}	1 401	1 024	912
Net earnings	1 669	974	846
Cash flow ²	3 372	2 276	1 688
Per share (dollars)			
Earnings from operations ^{1,2}	5.29	3.90	3.44
Net earnings – basic	6.30	3.71	3.19
Net earnings – diluted	6.23	3.67	3.16
Cash flow ²	12.73	8.66	6.37
Dividends	0.40	0.40	0.40
Expenditures on property, plant and equipment and exploration	2 315	1 861	1 681
Return on capital employed (per cent)	18.9	13.9	14.8
Operating return on capital employed (per cent) ^{1,2}	16.1	14.5	15.8
Cash flow return on capital employed (per cent) ²	37.1	30.5	28.2
Debt	2 229	3 057	1 401
Debt to debt plus equity (per cent)	22.4	34.6	22.3
Debt to cash flow (times)	0.7	1.3	0.8

1 Earnings from operations are earnings before gains or losses on foreign currency translation and on disposal of assets.

2 Refer to the non-GAAP measures disclosures on page 6, footnotes 1, 2 and 3 of Management's Discussion and Analysis.

OPERATING

Total production before/after royalties (thousands of barrels of oil equivalent per day) ¹	465/360	382/295	197/158
Crude oil and natural gas liquids production, before/after royalties (thousands of barrels per day)	320/248	245/189	77/69
Natural gas production, before/after royalties, excluding injectants (millions of cubic feet per day)	868/670	825/638	714/533
Proved reserves of crude oil and equivalents including synthetic crude oil, before/after royalties (millions of barrels)	796/650	830/657	450/393
Proved natural gas reserves, before/after royalties (trillions of cubic feet)	2.5/2.0	2.8/2.1	2.2/1.7
Refined petroleum product sales (thousands of cubic metres per day)	56.8	55.7	54.5
Refinery crude capacity utilization (per cent)	100	101	96

1 Natural gas production is converted using 6 000 cubic feet of gas for one barrel of oil.

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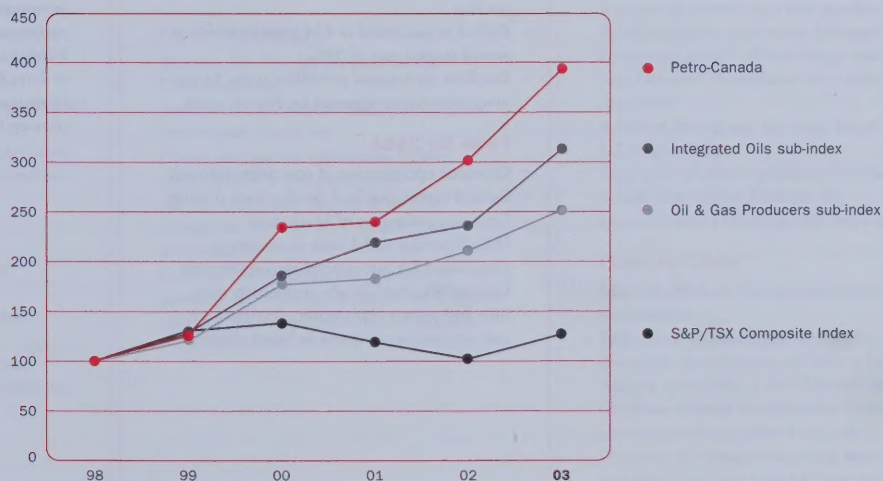
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Building sustained
PROFITABILITY
in our base businesses

Investing with discipline for
PROFITABLE GROWTH

- Exceptional financial performance achieved
- Integrated oil sands strategy reconfigured
- Long-term profitability improved by refinery consolidation
- International growth strategy advanced
- Flexibility to pursue new opportunities provided by strong balance sheet

Five-Year Share Price Performance



Petro-Canada shares rose 293 per cent from year-end 1998 through 2003, rising 31 per cent in 2003 alone.

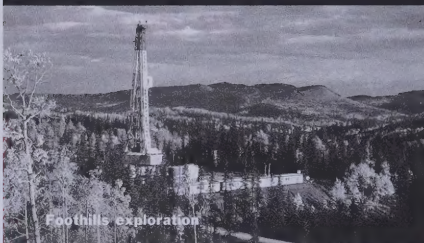
(December 31, 1998 = 100)

Changes in yearly closing values for Petro-Canada shares compared with the Toronto Stock Exchange (S&P/TSX Composite Index), the TSX Integrated Oils sub-index and the TSX Oil & Gas Producers sub-index.

Core Businesses at a Glance

*Petro-Canada is
strategically focused on
five core businesses:*

NORTH AMERICAN GAS



Foothills exploration

Business Description

- Explores for, produces and markets natural gas and associated liquids
- Among the larger producers in Western Canada
- Exploring in the Alberta Foothills, southeastern Alberta, west central Alberta, and northeastern British Columbia, and longer term in North American opportunity areas

Strategies

- Maximize profitability in Western Canada through focused exploration and development in our core areas – the Alberta Foothills, southeastern Alberta, west central Alberta, and northeastern British Columbia
- Maintain focus on capital investment performance and operating efficiency
- Pursue high-potential exploration plays in North America, including the Mackenzie Delta/Corridor, offshore Nova Scotia and Alaska
- Add new core areas through focused exploration and acquisitions

2003 Achievements

- Gas production averaged 693 million cubic feet per day
- Crude oil and natural gas liquids production in Western Canada averaged 16 900 barrels per day
- Drilled or partnered in 434 gross wells for an overall success rate of 92%
- Excellent operational reliability at the 11 gas processing plants operated by Petro-Canada

Plans for 2004

- Continue optimization of core assets through focused exploration and development drilling
- Continue evaluation of Mackenzie Delta/Corridor and Alaska properties in preparation for future pipeline construction
- Increase Western Canada exploration over time and pursue exploration, development and acquisition prospects in North America

EAST COAST OIL



Terra Nova FPSO

Business Description

- Explores for, develops, produces and markets oil from offshore Newfoundland
- 34% interest in, and operator of, the Terra Nova oil field
- 20% interest in the Hibernia oil field
- 27.5% interest in the White Rose oil field under development
- Interests in other significant discoveries and exploration acreage

Strategies

- Expand light oil production base offshore Newfoundland, capitalizing on experience gained in developing the Hibernia and Terra Nova oil fields
- Pursue high-potential exploration plays

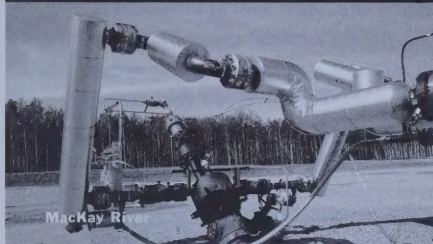
2003 Achievements

- Strong operating performance at Terra Nova and Hibernia increased Petro-Canada's share of production to a record 86 100 barrels per day
- Construction of White Rose development facilities continued to progress; glory holes completed and drilling of the first development wells commenced

Plans for 2004

- Progress toward top quartile safety, environmental, operating and drilling performance
- Further evaluation of growth opportunities at Terra Nova and Hibernia
- Continue White Rose development, targeting start-up in early 2006

OIL SANDS



Business Description

- 12% working interest in the Syncrude oil sands mining operation
- 100% working interest in the MacKay River *in situ* oil sands operation
- Interests in about 300 000 net acres of prospective *in situ* oil sands leases
- Converting the Edmonton refinery's conventional crude oil train to process oil sands feedstock exclusively

Strategies

- Phased development of reserves to benefit from learnings and respond to evolving market conditions
- Integrate oil sands production with the Edmonton refinery
- Improve Syncrude reliability and expand production

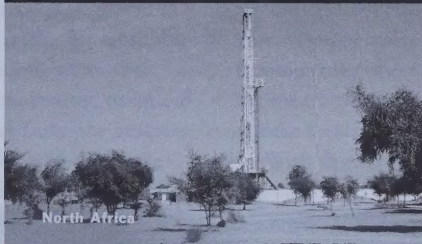
2003 Achievements

- Continued the third phase of Syncrude expansion. Petro-Canada's share of Syncrude production averaged 25 400 barrels per day
- Continued to ramp up production at MacKay River toward design capacity of 30 000 barrels per day. Production averaged 18 600 barrels per day in December 2003
- Completed third-party construction and commenced commissioning of the 165 megawatt MacKay River co-generation plant
- Reached agreement with Suncor to process MacKay River bitumen production and supply sour synthetic crude oil for upgrading at the Edmonton refinery
- Announced plan to reconfigure the Edmonton refinery to process bitumen and sour synthetic crude oil feedstock

Plans for 2004

- Continue third phase of the Syncrude expansion
- Achieve design capacity production rates at MacKay River
- Continue to delineate bitumen resources
- Commence detailed engineering on Edmonton refinery feedstock conversion

INTERNATIONAL



Business Description

- Explores for, develops, produces and markets oil and natural gas
- Production and exploration interests focused in three regions: Northwest Europe, North Africa/Near East, and Northern Latin America

Strategies

- Expand and exploit existing portfolio of assets
- Target new theatres of operation and acquisitions
- Develop a balanced exploration program

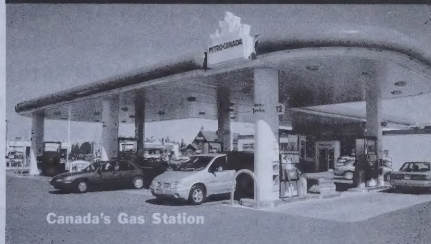
2003 Achievements

- Added new operated exploration opportunities in North Africa/Near East
- Acquired assets in the United Kingdom and Netherlands North Sea to increase working interest and provide new opportunities
- First oil at Clapham in the U.K. North Sea achieved in November
- First gas at L5b in the Netherlands North Sea achieved mid-October
- Start-up of Train 3 at the Atlantic LNG facility in Trinidad, increasing production to 60 million cubic feet per day net to Petro-Canada
- Joined bidding consortia for large scale opportunities in the Middle East

Plans for 2004

- Sanction the Pict development in the U.K. North Sea
- Sanction the De Ruyter development in the Netherlands North Sea
- Pursue incremental exploration licence opportunities in our focus areas
- Bid for, and where successful, execute agreements for large scale Middle East developments
- Build on our Atlantic LNG business by pursuing opportunities to build and integrate with our North American market position

DOWNSTREAM



Business Description

- Converts crude oil into refined products including gasoline, diesel, lubricants and asphalt
- Operates three refineries representing 17% of Canada's refining capacity
- Markets refined petroleum products and services through a nationwide network of retail and wholesale outlets
- Canada's second largest marketer of refined petroleum products with a 17% share of market
- Manufactures and markets high-quality specialty lubricants

Strategies

- Generate superior returns by focusing on first-quartile operating performance, being the brand of choice for Canadian gasoline consumers, building on our marketplace strengths, and increasing sales of high-margin specialty lubricants

2003 Achievements

- Began consolidation of Eastern Canada refining operations in Montreal, representing a major step forward to improve the long-term profitability of the Downstream
- Announced plans to convert the Edmonton refinery's conventional crude oil train to oil sands feedstock
- Successfully started up a new gasoline desulphurization unit at the Montreal refinery
- Continued growth of new-image retail sites increased convenience store sales by more than 16%
- Achieved throughput per retail site of 4.2 million litres
- Total sales of refined products increased to a record 56.8 million litres per day
- Increased sales of high-margin lubricants by 5%

Plans for 2004

- Maintain focus on first quartile operating performance
- Refocus on operating plant reliability
- Complete consolidation of Eastern Canada refining operations at the Montreal refinery
- Continue refinery modifications to meet future environmental regulations for fuels
- Continue to upgrade marketing networks and deliver increased sales of non-petroleum products and services
- Further increase lubricant sales into higher-margin markets

To Our Shareholders



In 2003, we demonstrated the robustness of our strategy, the benefits of our disciplined execution and our ability to position for growth. We remain convinced that patience, discipline, creativity and a steadfast conviction are the necessary ingredients for successful implementation of our growth strategy.

2003 – ADVANCING OUR STRATEGY

Our financial results in 2003 speak for themselves and demonstrate our ability to execute. In 2003, we reported earnings from operations of over \$1.4 billion – the highest in our corporate history – and earned a return on capital employed of 18.9 per cent. These results allowed us to further strengthen our balance sheet. While we enjoyed a robust business environment, our results also reflected our strong focus on controllables. We were not without our disappointments as we struggled with operational reliability in the Downstream and Oil Sands businesses. However, in our North American Gas, East Coast Oil and International businesses, we performed well with disciplined execution. With a large new portfolio of international assets and ever-growing shareholder expectations, we set about improving profitability and finding new ways to further our long-term growth strategy.

An area of particular pride for me as I look back on the year is the advancement we made on that front. My philosophy of establishing strategic focus and then pursuing that strategy with discipline was tested and confirmed.

In Oil Sands, our initial plans to create an integrated growth strategy with large-scale investments at the Edmonton refinery faced significant cost increases as we drew on industry experience to develop our cost estimates. Some may have forged ahead hoping for a stronger business environment. We chose to remain true to our capital discipline and took the time to re-think the project. A mere seven months later, we announced a new scaled back and phased approach with much better economics. With this, I believe we demonstrated the importance of discipline to ensure our investments are truly value adding.

We also made great strides on the international front. With the integration of the assets behind us, we set our strategy to grow internationally and we've made early,

measured advances. With our experience as an operator, we acquired properties in the North Sea to build on our existing assets, and brought two new developments on stream that were on time and on budget. Importantly, we also resolved to establish a much stronger exploration program – one that will yield improvements in exploration success and significantly add to our reserves over time. By year-end we had acquired a number of attractive exploration blocks in and around our core areas. Finally, the third component of our international strategy – seeking new opportunities – led to serious discussions on several new areas, including a gas to liquids initiative in Qatar, and the re-development of the northern fields in Kuwait. Neither of these opportunities is a certainty at this stage and we definitely need more of these in the portfolio.

In 2003, we also continued to effectively deal with organizational change. On behalf of my fellow Board members and management, I would like to convey our sincere thanks to Norm McIntyre, who retired as President on February 15, 2004. His contributions to the success of the Corporation have been tremendous, the most recent being his superb job integrating our international acquisition into Petro-Canada's operations. During 2003, we proactively brought Peter Kallos on board and his extensive international experience combined with his exposure to Petro-Canada's leadership team and management processes allowed us to complete a successful transition. Peter has now succeeded Norm in the role of Executive Vice-President, International, based in our London office.

In summary, in 2003, we demonstrated the robustness of our strategy, the benefits of our disciplined execution and our ability to position for growth. We remain convinced that patience, discipline, creativity and a steadfast conviction are the necessary ingredients for successful implementation of our growth strategy.

LOOKING AHEAD – STAYING THE COURSE

As we look forward to 2004 and beyond, I believe it will be even more critical to stick to the principles that have made us successful to date. Particular emphasis will be placed on operating our facilities reliably and safely. We must also ensure that we maintain a focus on the long term. Our growth may not be linear from quarter to quarter, or indeed from year to year. Our growth may shift from one business to another as value-adding opportunities arise. But if we consistently manage our business based on the profitability we expect to generate from each new dollar of capital invested, our future will mirror our successful past.

In Oil Sands, we will invest in our Edmonton refinery to enable it to run entirely on oil sands-based feedstocks. We will also continue to evaluate where to begin our next SAGD development. Advances in technology and applying the learnings from our MacKay River plant will be critical to these next steps.

In the Downstream, we will implement the decision we made in 2003 to close our Oakville refinery and convert it to a terminal. As we carry out these plans and expand our Montreal refinery, we look to the professionalism and commitment of a very dedicated group of employees to help us improve the long-term profitability of this business. We also look to our marketing group to continue to find new and innovative ways to increase the returns from the highly competitive gasoline business. I know that advances in this business are hard-won. But I believe 'Canada's Gas Station' can continue to create value for customers and our shareholders.

In North American Gas, we face – as does the industry as a whole – an ever-increasing challenge to find the right balance between production growth and profitability. To improve our reserves replacement ratio and stem production declines, we are steadily increasing our exploration activity and pursuing opportunities to add reserves and production outside of our core areas. Once again, a focus on profitability and disciplined investment will yield solid long-term returns for us. We must remain vigilant about costs, highly selective about opportunities, and leverage our strengths.

On the East Coast, our challenge is to prolong the profitability we are enjoying from the Terra Nova and Hibernia assets. By advancing strategies to extend the pool of reserves feeding into these two offshore facilities, we plan to generate ongoing benefits from our investment. In addition, working with the operator, Husky, we look forward to the White Rose project coming on stream in early 2006.

Internationally, a stepped up exploration program and active business development will complement a solid base of operations. With our focus on the North Africa/Near East, Northwest Europe and Northern Latin America regions, we believe we have the sound asset base and business capability needed to be successful.

Overall, we will continue to improve the profitability of the base businesses while pursuing profitable growth.

GROWING – IN A RESPONSIBLE WAY

Increasing our international involvement has placed an even greater emphasis on some of the core values we've always held at Petro-Canada. Whether it's operating in an environmentally friendly way, participating in the communities where we live and work, or valuing diversity, the values we apply in our Canadian operations must remain intact when we operate overseas.

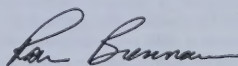
With climate change and the Kyoto protocol continuing to attract much attention, our focus on environmental stewardship is critical. Our total Canadian greenhouse gas emissions in 2002 (the most recent year for which data is available) were nine per cent above 1990 levels, even though our combined Upstream and Downstream production grew by 51 per cent over the same period. Going forward, we have plans in place to continually reduce the impact of our facilities and our products on the environment.

We also play a very active role in the communities where we live and work – in 2003, we donated approximately \$15 million in cash and in-kind contributions to non-profit organizations. I take great pride as well in the time and effort our employees devote to worthy causes in their communities.

We take our role as a corporate citizen very seriously, believing we have high standards to uphold and a solid reputation to preserve. We have always had very strong corporate governance with our well-respected Board of Directors playing an active role. To improve disclosure, we've taken steps to enhance reporting to shareholders by providing more information and making it easy to access through our Web site. You may notice, for example, that the print version of this annual report is presented in a very simple and low-cost manner, as we shift the primary focus of our communications with investors to our Web site.

OUR COMMITMENT TO THE FUTURE

Whether we're adding to our exploration program, investing in the community, or re-building a gas station, I apply the same tests to determine whether we're going in the right direction. Are we building for the long term? Are we focusing on what we can control? Are we spending our money wisely, delivering the best returns to shareholders? To me, all of these questions lead back to a steadfast implementation of our core strategy – to improve how we run our businesses, day to day, and create additional value by growing our business the best way we know how for the long term. Our strong track record and ongoing value creation signal a bright future ahead.



Ron Brenneman
President and Chief Executive Officer

Management's Discussion & Analysis

Management's Discussion and Analysis (MD&A) should be read in conjunction with the Financial Statements and Notes included in this annual report. Financial data has been prepared in accordance with Canadian generally accepted accounting principles (GAAP), unless otherwise specified. All dollar values are Canadian dollars, unless otherwise indicated. All oil and gas production and reserves volumes are stated before deduction of royalties, unless otherwise indicated. Graphs accompanying the text identify our 'value drivers', key measures of performance in each component of our business.

RESULTS OF OPERATIONS

Shareholder Value

Shareholder value grew 31.5 per cent through share price appreciation and dividends in 2003.



■ One-year return (per cent)
■ Three-year average return (per cent)
– Shareholder value measures the change in the Petro-Canada share price plus dividend returns.

ANALYSIS OF CONSOLIDATED EARNINGS AND CASH FLOW

Consolidated Financial Results

(millions of dollars, unless otherwise indicated)

	2003	2002	2001
Earnings from operations ^{1,3}	\$ 1 401	\$ 1 024	\$ 912
Gain (loss) on foreign currency translation	239	(52)	(96)
Gain on disposal of assets	29	2	30
Net earnings	\$ 1 669	\$ 974	\$ 846
Earnings per share (dollars) – basic	\$ 6.30	\$ 3.71	\$ 3.19
– diluted	6.23	3.67	3.16
Cash flow ^{2,3}	3 372	2 276	1 688
Cash flow per share (dollars)	12.73	8.66	6.37
Debt	2 229	3 057	1 401
Cash and cash equivalents	635	234	781
Average capital employed	\$ 9 392	\$ 7 826	\$ 6 259
Return on capital employed (per cent)	18.9	13.9	14.8
Operating return on capital employed (per cent)	16.1	14.5	15.8
Return on equity (per cent)	24.7	18.3	18.1

- 1 Earnings from operations, which represents net earnings excluding gains or losses on foreign currency translation and on disposal of assets, is used by the Company to evaluate operating performance.
- 2 Cash flow, which is expressed before changes in non-cash working capital items, is used by the Company to analyze operating performance, leverage and liquidity.
- 3 Earnings from operations and cash flow do not have any standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP) and, therefore, may not be comparable with the calculation of similar measures for other companies.

This Management's Discussion and Analysis ("MD&A") contains forward-looking statements. Such statements are generally identifiable by the terminology used, such as "plan", "anticipate", "intend", "expect", "estimate", "budget" or other similar wording. Forward looking statements include but are not limited to: references to future capital and other expenditures; drilling plans; construction activities; the submission of development plans; seismic activity; refining margins; oil and gas production levels and the sources of growth thereof; results of exploration activities and dates by which certain areas may be developed or may come on-stream; retail throughputs; pre-production and operating costs; reserves estimates; reserves life; natural gas export capacity; and environmental matters. These forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; refining and marketing margins; the ability to produce and transport crude oil and natural gas to markets; the results of exploration and development drilling and related activities; fluctuation in interest rates and foreign currency exchange rates; the ability of suppliers to meet commitments; actions by governmental authorities including increases in taxes; decisions or approvals of administrative tribunals; changes in environmental and other regulations; risks attendant with oil and gas operations; and other factors, many of which are beyond the control of Petro-Canada. These factors are discussed in greater detail in filings made by Petro-Canada with the Canadian provincial securities commissions and the United States Securities and Exchange Commission ("SEC").

Petro-Canada's staff of qualified reserves evaluators generate the reserves estimates used by this corporation. Our reserves staff and management are not considered independent of the corporation for purposes of the Canadian provincial securities commissions. The use of terms such as "probable", "possible", "recoverable" or "potential" reserves and resources does not meet the guidelines of the SEC for inclusion in documents filed with the SEC. Petro-Canada has obtained an exemption from certain Canadian reserves disclosure requirements to permit it to make disclosure in accordance with SEC standards in order to provide comparability with U.S. and other international issuers. Therefore, Petro-Canada's reserves data and other oil and gas formal disclosure is made in accordance with U.S. disclosure requirements and practices and may differ from Canadian domestic standards and practices. Where the term boe (barrel of oil equivalent) is used in this MD&A it may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Readers are cautioned that the foregoing list of important factors affecting forward-looking statements is not exhaustive. Furthermore, the forward-looking statements contained herein are made as of the date of this MD&A, and Petro-Canada does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement.

2003 COMPARED WITH 2002

Stronger commodity prices and margins combined with higher production volumes to boost earnings from operations to a record \$1 401 million in 2003. Net earnings, including gains on foreign currency translation and disposals of assets, and cash flow rose to record levels. The improved financial performance reflected higher prices for natural gas, an additional four months of operations from International assets acquired in May 2002, increased production from East Coast Oil, higher refinery cracking margins and positive adjustments for income tax rate changes and International provisions. Offsetting factors included after-tax charges of \$151 million for the consolidation of Eastern Canada refinery operations, \$82 million for the write-off of costs related to the original Edmonton refinery conversion plan and a \$46 million provision related to the impending sale of a non-core asset in Kazakhstan.

Earnings from Operations

Variance Factors – 2003 compared with 2002

(millions of dollars, after tax)

2002 Earnings from operations	\$ 1 024
Higher Upstream commodity prices ¹	338
Increased Upstream production volumes ^{2,3}	279
Increased Downstream margins	143
Adjustment to International provisions	45
Decrease in the provision for future income taxes ⁴	45
Decrease in depreciation, depletion and amortization, and exploration expense ^{3,5}	31
Increased operating and G&A costs ⁶	(183)
Costs related to the planned shutdown of Oakville refinery	(151)
Costs related to revised Edmonton refinery feedstock conversion plan	(82)
Asset impairment in Kazakhstan	(46)
Other	(42)
2003 Earnings from operations	\$ 1 401

1 The major portion relates to higher natural gas price realizations in Canada.

2 Reflects four additional months of International activity, 10 additional months of MacKay River operations and significant volume gains at Hibernia and Terra Nova.

3 The impact of higher volumes on depreciation, depletion and amortization expense is included in production volume variance.

4 Reflects income tax adjustments related to federal and provincial rate changes.

5 Excludes depreciation, depletion and amortization related to costs associated with the Oakville shutdown, the Edmonton refinery feedstock conversion and the Kazakhstan asset impairment.

6 Reflects four additional months of International activity and 10 additional months of MacKay River operations.

Consolidated 2003 cash flow was \$3 372 million compared with \$2 276 million in 2002. Cash flow in 2003 reflected the higher operating earnings, about \$120 million of net deferrals of current income taxes related to earnings of the Petro-Canada Oil and Gas Partnership (PCOG) and about a \$25 million decrease in current income taxes resulting from the inventory valuation method prescribed for income tax purposes in the Downstream. In 2002, net deferrals related to earnings of PCOG increased current taxes by about \$50 million and the inventory valuation method increased current taxes by about \$85 million.

The increased returns on equity and capital employed resulted primarily from the 71 per cent improvement in net earnings.

QUARTERLY INFORMATION

Consolidated Quarterly Financial Results

(millions of dollars, unless otherwise indicated)

	2003				2002			
	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Quarter 1	Quarter 2	Quarter 3	Quarter 4
Total revenue	\$ 3 507	\$ 2 826	\$ 2 959	\$ 2 929	\$ 1 708	\$ 2 437	\$ 2 767	\$ 3 005
Net earnings	583	585	301	200	88	321	209	356
Earnings per share (dollars)								
– basic	2.21	2.21	1.13	0.75	0.34	1.22	0.79	1.35
– diluted	\$ 2.18	\$ 2.18	\$ 1.12	\$ 0.75	\$ 0.33	\$ 1.21	\$ 0.79	\$ 1.34

Earnings from Operations and Cash Flow

Earnings from operations were \$1.4 billion in 2003.



– Earnings from operations do not include gains or losses on foreign currency translation and on disposal of assets.

Operating Return on Capital Employed

Operating return on capital employed reflected higher earnings due to a stronger business environment.



– Earnings from operations do not include gains or losses on foreign currency translation and on disposal of assets.

Variances from quarter to quarter in revenues and net earnings resulted mainly from: fluctuations in commodity prices and refinery cracking margins; the acquisition of international producing properties effective May 2, 2002; the impact on production and processed volumes from maintenance and other shutdowns at major facilities; and the level of exploration drilling activity, particularly in high-cost frontier and offshore areas. Other significant factors affecting 2003 net earnings included after-tax charges of \$46 million in the first quarter related to the pending Kazakhstan asset sale, \$136 million in the third quarter for the consolidation of our Eastern Canada refinery operations, and \$82 million in the fourth quarter related to the revised Edmonton refinery conversion plan. Income tax rate changes increased first quarter earnings by \$96 million and decreased fourth quarter earnings by \$51 million in 2003. In addition, gains on foreign currency translation were also a significant factor, particularly in the first and second quarters of 2003.

For further analysis of quarterly results, refer to Petro-Canada's quarterly reports to shareholders available on the Web site at www.petro-canada.ca.

BUSINESS ENVIRONMENT

Economic factors influencing Petro-Canada's Upstream financial performance include crude oil and natural gas prices, and foreign exchange rates, particularly the Canadian dollar/U.S. dollar rate. Factors of supply and demand, weather, political events and the level of industry product inventories affect prices for energy commodities. Factors influencing Downstream performance include the level and volatility of crude oil prices, industry refining margins, movements in light/heavy crude oil price differentials, demand for refined petroleum products and the degree of market competition.

Business Environment in 2003

During 2003, U.S. dollar-denominated international crude oil prices reached their highest annual average since 1982. The strength of international crude prices in 2003 was due to a confluence of geopolitical and market factors. OPEC decision-making, supported by production discipline among member nations, continued to be the major factor in keeping prices high. Additionally, a general strike in Venezuela, the war in Iraq and political unrest in Nigeria reduced crude oil supplies. As well, a very cold winter in the Northern Hemisphere and the resumption of economic growth in key consuming areas led to a tight global supply/demand situation. The strengthening of the Canadian dollar throughout 2003 dampened the impact of increased international oil prices on Canadian prices. The value of the Canadian dollar rose from 63.3 cents US on December 31, 2002 to 77.4 cents US on December 31, 2003, an unprecedented 12-month increase of 14.1 cents US or 22.3 per cent.

Colder-than-normal weather in North America during the first quarter of 2003 led to rising natural gas prices. Strong gas injection activity to replenish depleted storage levels lent support to prices from April through October. In the fourth quarter, gas prices lost some of the gains made during the injection season as the heating season began with close-to-normal levels of gas in storage.

In the Canadian industry's downstream sector, refined product sales in 2003 grew by approximately 4.7 per cent compared with 0.8 per cent in 2002. Refining margins also noticeably improved, reflecting the strong refined product sales and substantially wider light-heavy crude price differentials.

Commodity Price Indicators and Exchange Rates

(averages for the years indicated)

	2003	2002
Crude oil price indicators (per barrel):		
Dated Brent at Sullom Voe	US\$ 28.84	US\$ 24.98
West Texas Intermediate (WTI) at Cushing	US\$ 31.04	US\$ 26.08
WTI/Brent price differential	US\$ 2.20	US\$ 1.10
Brent/Maya price differential	US\$ 4.61	US\$ 4.08
Edmonton Light	Cdn\$ 43.77	Cdn\$ 40.41
Edmonton Light/Bow River (heavy) price differential	Cdn\$ 11.67	Cdn\$ 8.90
Natural gas price indicators:		
At Henry Hub – per million British thermal units (mmbtu)	US\$ 5.44	US\$ 3.25
AECO spot – per thousand cubic feet (mcf)	Cdn\$ 6.99	Cdn\$ 4.24
Henry Hub-AECO-C basis differential – per mmbtu	US\$ 0.70	US\$ 0.66
New York Harbor 3-2-1 refinery crack spread – per barrel	US\$ 5.31	US\$ 3.36
US\$ per Cdn\$ exchange rate	US\$ 0.714	US\$ 0.637

The stronger Canadian dollar dampened the impact of higher commodity prices in 2003.

Outlook for Business Environment in 2004

Prices for energy commodities are expected to remain volatile in 2004, reflecting the vagaries of weather, the level of industry inventories, and political and natural events. Current low global crude inventories combined with cold winter weather, uncertainty about the reliability of Iraq's oil infrastructure and the political stability of Venezuela and Nigeria are expected to maintain international oil prices near record levels. Given the current low level of oil inventories worldwide and continuing growth in demand, the upward pressure on world oil prices is likely to be amplified by the recent OPEC decision to lower its production ceiling by one million barrels per day starting April 1, 2004.

We expect the North American natural gas supply/demand balance to remain tight in 2004, as low-cost supplies from conventional areas continue to decline despite very high drilling activity. In the absence of increased supplies, natural gas prices are expected to rise to the levels necessary to ration demand and re-balance the market.

In the industry's downstream sector, refined product margins are expected to face continued pressure from high and volatile crude oil costs, particularly during the first half of 2004, resulting in lower margins than in 2003. Expectations of improving economic conditions lead management to anticipate, weather trends aside, another year of positive growth in domestic sales of refined products.

Petro-Canada's businesses are managed for the long term.

Economic Sensitivities

The following table shows the estimated after-tax effects that changes in certain factors would have had on Petro-Canada's 2003 net earnings, had these changes occurred. These calculations are based on business conditions, production and sales volumes realized in 2003.

Sensitivities Affecting Net Earnings

Factor ¹	2003 Averages	Increase	Impact on Net Earnings
(millions of Canadian dollars)			
Upstream			
Price received for crude oil and liquids	\$38.80/bbl	\$1.00/bbl ²	\$ 48
Price received for natural gas	\$6.16/mcf	\$0.25/mcf	36
Production of crude oil and liquids	319 900 barrels per day (b/d)	1 000 b/d	4
Production of natural gas available for sale	868 million cubic feet per day (mmcf/d)	10 mmcf/d	6
Exchange rate (impact on Upstream earnings):			
Cdn\$ per US\$	Cdn \$1.401	Cdn \$0.01	(39)
Downstream			
New York Harbor 3-2-1 crack spread ³	US\$5.31/bbl	US\$0.10/bbl	4
Light/heavy crude price differential ⁴	\$11.67/bbl	\$1.00/bbl	11
Corporate			
Exchange rate: Cdn\$ per US\$ ⁵	Cdn \$1.401	Cdn \$0.01	\$ 9

1 The impact of a change in one factor may be compounded or offset by changes in other factors. This table does not consider the impact of any inter-relationship among the factors. The application of these factors may not necessarily lead to an accurate prediction of future results of operations. We may undertake risk management initiatives from time to time that affect these sensitivities.

2 This sensitivity is based upon an equivalent change in the price of WTI and North Sea Brent. In 2003, WTI averaged US\$31.04 per barrel (bbl) and North Sea Brent averaged US\$28.84/bbl.

3 New York Harbor 3-2-1 crack spread applies mainly to Eastern Canada markets.

4 This refers to the spread between the prices of benchmark Edmonton Light and Bow River (heavy) crude oils.

5 This refers to gains or losses on a portion (US\$873 million) of the Company's long-term debt. Gains or losses on foreign currency denominated long-term debt associated with the self-sustaining International business segment are deferred and included as part of shareholders' equity.

Oil and Gas Production

Production increased due to an additional four months of International operations and higher East Coast Oil and Oil Sands production.



■ Upstream production (thousands of barrels of oil equivalent per day)

UPSTREAM

Petro-Canada's Upstream operations consist of four business segments: North American Gas, with current production in Western Canada; East Coast Oil, with three major developments offshore Newfoundland; Oil Sands operations in northeastern Alberta; and International, where we are active in three core areas: Northwest Europe, North Africa/Near East; and Northern Latin America. Our diverse asset base provides a balanced portfolio and a platform for longer-term growth.

In 2003, Petro-Canada's worldwide production before royalties averaged 319 900 barrels per day (b/d) of oil and liquids and 868 million cubic feet per day (mmcf/d) of natural gas, or a record 464 500 barrels of oil equivalent per day (boe/d). A significant portion of the 21 per cent increase from the 2002 level of 382 400 boe/d is related to the additional four months of International operations.

Production	North American Gas	East Coast Oil	Oil Sands	International	Total
2002 Average Daily Volumes					
Crude oil, NGL and bitumen (b/d)					
net before royalties	18 900	71 900	1 100	125 500	217 400
net after royalties	14 200	70 900	1 000	75 200	161 300
Synthetic crude oil (b/d)					
net before royalties	—	—	27 500	—	27 500
net after royalties	—	—	27 200	—	27 200
Natural gas (mmcf/d)					
net before royalties	722	—	—	103	825
net after royalties	558	—	—	80	638
Total volumes (boe/d)					
net before royalties	139 200	71 900	28 600	142 700	382 400
net after royalties	107 200	70 900	28 200	88 500	294 800
2003 Average Daily Volumes					
Crude oil, NGL and bitumen (b/d)					
net before royalties	16 900	86 100	10 700	180 800	294 500
net after royalties	12 600	84 000	10 600	115 600	222 800
Synthetic crude oil (b/d)					
net before royalties	—	—	25 400	—	25 400
net after royalties	—	—	25 100	—	25 100
Natural gas (mmcf/d)					
net before royalties	693	—	—	175	868
net after royalties	521	—	—	149	670
Total volumes (boe/d)					
net before royalties	132 300	86 100	36 100	210 000	464 500
net after royalties	99 500	84 000	35 700	140 400	359 600

North American Gas

North American Gas Financial Results

(millions of dollars)

	2003	2002	2001
Earnings from operations	\$ 479	\$ 180	\$ 463
Gain (loss) on sale of assets	33	(1)	29
Net earnings	\$ 512	\$ 179	\$ 492
Cash flow	\$ 985	\$ 534	\$ 651
Expenditures on property, plant and equipment and exploration	\$ 560	\$ 530	\$ 548
Total assets	\$ 2 301	\$ 2 240	\$ 2 129

2003 COMPARED WITH 2002

Higher prices for natural gas and solid operating performance boosted earnings from operations for North American Gas to a record \$479 million in 2003, 166 per cent higher than in the previous year.

The exceptional financial result also reflected a \$60 million pre-tax decrease in exploration expense due to reduced activity in the Mackenzie Delta/Corridor and the Scotian Slope.

Petro-Canada's natural gas price realizations averaged \$6.50/mcf, up 62 per cent from \$4.01/mcf in 2002, due to tighter market conditions for natural gas for a large part of the year. Natural gas production averaged 693 mmcf/d in 2003, down from 722 mmcf/d in 2002, as additional volumes from ongoing development were insufficient to offset declines in older fields. Production of conventional crude oil and natural gas liquids production in Western Canada averaged 16 900 b/d, down from 18 900 b/d in 2002, mainly as the result of non-core asset sales. The asset sales, representing production of about 10 mmcf/d of natural gas and 2 000 b/d of oil and natural gas liquid, resulted in an after-tax gain of \$33 million. Operating and overhead costs in 2003 were \$0.67 per thousand cubic feet of gas equivalent (mcf), up from \$0.57/mcf in the previous year, reflecting lower volumes and higher utility and labour costs.

Western Canada Operating and Overhead Costs

Cost per unit was up due to lower volumes and higher utility and labour costs.



■ Unit operating and overhead costs (\$ per thousand cubic feet of gas equivalent)

— Includes Western Canada gas, conventional oil and liquids.

**Our strategy in
North American Gas
is to sustain
long-term profitability.**

STRATEGY

Petro-Canada is one of the larger producers of natural gas in Western Canada. Our goal is to maintain exceptional profitability in Western Canada, while positioning ourselves for longer-term opportunities.

Our strategy is to:

- Capitalize on opportunities in the Western Canada Sedimentary Basin, balancing profitability with production growth.
- Maintain focus on capital investment performance and operating efficiency.
- Optimize existing core properties and add new core areas through focused exploration and acquisitions.
- For the longer term, pursue high-potential exploration in the Mackenzie Delta/Corridor, on the Scotian Slope and in Alaska.

Executing the strategy

Capital expenditures in 2003 included \$472 million for exploration and development of natural gas in Western Canada and \$58 million for other natural gas opportunities in North America, principally in the Mackenzie Delta/Corridor. Capital spending was above plan due to increased development drilling activity and a \$30 million acquisition of a 60 per cent interest in the Savanna Creek gas field in southwest Alberta. Exploration and development drilling activity in Western Canada in 2003 resulted in 421 gross successful wells, for a success rate of 92 per cent.

In Western Canada we are focused on four core areas – the Alberta Foothills, northeastern British Columbia, southeastern Alberta, and west-central Alberta. In the Foothills, we have developed a strong technical competency in finding, developing and operating deep sour gas. A key feature of our strategy has been concentric exploitation in and around existing developments and infrastructure, such as the area surrounding the Petro-Canada operated Hanlan gas plant in the northern Foothills. Through the successful drilling of multiple Turner Valley structures, combined with successful sweet gas exploration

and development in the Narraway area, we have increased production in the Hanlan region from an average of 105 mmcf/d in 2000 to 138 mmcf/d exiting 2003. Results from the 2003 drilling program included 10 successful Turner Valley wells. Additionally, follow-up drilling in 2003 on a 2002 Wabamum discovery has resulted in four horizontal wells, each capable of about 10 mmcf/d of gross production. Drilling plans for the Hanlan area in 2004 include the drilling of a further six Turner Valley wells and additional wells in the Wabamum.

In the shallow gas region of southeastern Alberta our annual drilling program resulted in 322 gross (204 net) successful wells, raising gas production to 70 mmcf/d at 2003 year end. To further support production volumes, we are reviewing opportunities to double the well spacing in our properties from the current four wells per section.

For longer-term growth, we continue to pursue frontier opportunities. Activity in 2003 included the initial drilling of our fifth exploration well in the Mackenzie Delta. The Nuna I-30, about 10 kilometres southwest of the successful Tuk M-18 well, was spudded in mid-February, later than originally planned due to an unseasonably warm start to winter weather. The well was suspended in April before reaching its target depth of 3 500 metres because of the onset of spring break-up. Offshore Nova Scotia, we continue to evaluate the results of an 1 800 square kilometre 3-D seismic program shot over a deep-water area northeast of Sable Island during 2003. In Alaska, we continue to review the prospectivity of our land position in the foothills area north of the Brooks mountain range. While our acreage is close to a proposed pipeline route to southern markets, we do not expect the region to be serviced by a pipeline this decade.

OUTLOOK

2004 production expectations:

- Western Canada production to average 640 mmcf/d of natural gas and 13 000 b/d of crude oil and natural gas liquids.

Growth plans:

- Increase Western Canada exploration over time to improve reserves replacement.
- Pursue exploration and development prospects in North America.
- Drill over 100 exploration and development wells and over 300 shallow gas wells in Western Canada.
- Advance exploration programs in the Mackenzie Delta/Corridor, Scotian Slope and Alaska.

2004 capital spending plans:

- \$460 million for Western Canada.
- \$35 million for Alaska and Mackenzie Delta/Corridor.

We're looking beyond core producing areas for new natural gas opportunities.

About \$460 million will be invested in new and existing Western Canada exploration and development opportunities. The \$35 million allocated to Alaska and the Mackenzie Delta/Corridor will enable us to assess future opportunities. While we continue to invest substantial amounts in Western Canada, this is proving to be insufficient to achieve 100 per cent reserves replacement because of the maturing nature of the region. Going forward, our strategy will continue to emphasize profitability through concentric exploitation of existing assets but will also include an expanded focus outside of existing core areas. Of the funding planned for 2004, \$170 million will target exploration opportunities.

We do not plan any natural gas drilling in Canada's frontier regions in 2004. In the Mackenzie Delta, the ongoing program has secured our most prospective acreage for future exploration and allowed us to make a non-binding nomination of 30 mmcf/d from our share of the Tuk gas pool to support the development proposal for the Mackenzie Valley pipeline. Pending further pipeline developments, our strategy is to defer any major activity in the Mackenzie Delta over the 2004 winter drilling season and re-evaluate our program next year. In Alaska, we will continue the technical analysis of our prospects and exploitation strategy.

East Coast Oil

East Coast Oil Financial Results

(millions of dollars)	2003	2002	2001
Earnings from operations and net earnings	\$ 593	\$ 430	\$ 168
Cash flow	\$ 869	\$ 687	\$ 338
Expenditures on property, plant and equipment and exploration	\$ 344	\$ 289	\$ 279
Total assets	\$ 2 247	\$ 2 209	\$ 2 090

2003 COMPARED WITH 2002

East Coast earnings from operations in 2003, at \$593 million, were up 38 per cent from 2002 due to production gains, strong operating performance and crude oil price improvements.

Petro-Canada's share of East Coast production before royalties rose to 86 100 b/d from 71 900 b/d the previous year, reflecting significant improvements at both Hibernia (Petro-Canada – 20 per cent working interest) and Terra Nova (Petro-Canada – 34 per cent working interest), despite severe weather conditions during the first quarter. The improvement at Hibernia, where gross field production climbed above 200 000 b/d for the first time, resulted from additional drilling and outstanding reservoir performance with lower than expected increases in the gas-oil and water-oil ratios. Approval by the Canada-Newfoundland Offshore Petroleum Board (CNOPB) to increase the average daily gross field production rate to 220 000 b/d enabled the production improvement. At Terra Nova, gross field production averaged 134 000 b/d (Petro-Canada share – 45 500 b/d), up from 105 400 b/d (Petro-Canada share – 35 800 b/d), in 2002, mainly due to the approval of an increase in the average daily gross field production rate from 100 000 b/d to 180 000 b/d by the CNOPB. Continued focus on reservoir management/optimization will enable us to maintain high reservoir production capability. The average price realized for our East Coast oil production in 2003 was \$39.91/bbl, up from \$38.84/bbl in 2002.

East Coast Oil operating and overhead costs averaged \$2.74/bbl in 2003, down from \$3.32/bbl in 2002. Hibernia operating costs were unchanged, while Terra Nova costs fell, reflecting the transition from start-up to steady state operations.

East Coast Oil Operating and Overhead Costs

Operating and overhead costs were lower due to high production volumes.



STRATEGY

We believe the East Coast offers exceptional opportunities for profitable growth in both the near term and the long term. Key features of our strategy are:

- Profitably expand reserves and production base.
- Continue to strive for top quartile safety and operating performance.
- Pursue high-potential exploration opportunities.

Executing the strategy

Petro-Canada's capital expenditures for exploration and development of crude oil offshore Canada's East Coast in 2003 amounted to \$344 million, with half related to the development of the White Rose oil field (Petro-Canada – 27.5 per cent working interest). Solid progress in 2003 kept the White Rose project on track for production start-up in early 2006. Key components of the project have either been completed or remain on schedule, except construction of the topsides for the project's Floating Production, Storage and Offloading vessel (FPSO). Concrete steps have been taken to make up for earlier delays in topsides and engineering and procurement and still deliver first oil in early 2006. At year-end 2003, construction of the FPSO, which has a planned gross production capacity of 100 000 b/d, was approximately two-thirds complete. Progress also was made during 2003 on fabrication of the subsea production systems. The first of the subsea wellhead assemblies was completed in November.

White Rose field development activity in 2003 included completion of three glory holes – nine-metre-deep excavations to protect the subsea wellheads and associated production equipment against icebergs, and commencement of the development drilling program. The White Rose development plan

Terra Nova and Hibernia continued to exceed production expectations in 2003.

includes the drilling of 19 to 21 wells to recover an estimated 200 million to 250 million barrels of oil over a 10- to 12-year time frame. Ten wells – five producing, four water injection and one gas injection – will be drilled prior to start-up. Petro-Canada's estimate of the project's total pre-production cost, including the first 10 wells, is \$2.3 billion. Estimated peak gross production from the project of 90 000 b/d is believed sustainable for about four years. Encouraging results from 2003 delineation drilling in a previously undrilled fault block south of the main reservoir indicate potential for incremental oil reserves.

Our plans to extend plateau production at Hibernia and Terra Nova focus on expanding existing developments, while also evaluating the potential for subsea tiebacks of smaller discoveries and prospects to the Hibernia and Terra Nova facilities. At Hibernia, assessment of the development potential of the Ben Nevis Avalon continues. A comprehensive evaluation is underway on the results of the B-44 appraisal well, drilled late in 2002. Analysis of the reservoir will determine if additional delineation drilling is necessary before further development is started or pursued.

At Terra Nova, our near-term goals are to optimize reservoir performance and delineate field limits. Activity in 2003 included drilling one injection and three production wells. We are evaluating development options for the adjoining Far East block, where a 2001 well encountered 80 metres of oil-bearing net pay in the Jeanne d'Arc sands. Two subsequent wells were dry and abandoned. We are currently evaluating drilling results and reprocessed seismic data to better understand the options, as well as drilling requirements and timing.

With an overall focus on base business profitability, good progress continued to be made towards top quartile safety and operating performance at each of our East Coast developments. Hibernia has already achieved top quartile operating performance and Terra Nova is incorporating lessons learned from Hibernia and North Sea operations in a planned process to achieve the same results. Opportunities to capture synergies between Hibernia, Terra Nova and White Rose are also being pursued to reduce costs and improve efficiency.

In deeper waters 450 kilometres off Newfoundland, two high-risk, high-potential exploration wells drilled in the Flemish Pass basin in 2003 failed to encounter commercial quantities of hydrocarbons. These wells were abandoned, with the related costs written off against earnings in 2003. Information gained from the wells, together with other exploration data, continue to be evaluated to determine our future plans for the area.

OUTLOOK

2004 production expectations:

- Petro-Canada's East Coast oil production to average 80 000 b/d.

Our production outlook takes into account a six-day potential shutdown at Terra Nova and a 10-day potential shutdown at Hibernia. We are investigating ways to minimize the duration of shutdowns at both fields.

Growth plans:

- Complete White Rose development by early 2006.
- Extend plateau production at both Hibernia and Terra Nova.

2004 capital spending plans:

- \$180 million for development of White Rose.
- \$140 million for ongoing Hibernia and Terra Nova drilling and development.

The ongoing high level of spending at White Rose, Hibernia and Terra Nova underscores the importance of these world-class projects to our long-term growth plans. Development spending at Hibernia and Terra Nova in 2004 will include drilling 14 wells – eight at Hibernia and six at Terra Nova. No exploratory drilling is planned for this offshore region in 2004.

Our strategy is to extend profitable East Coast oil production.

Oil Sands

Oil Sands Financial Results

(millions of dollars)	2003	2002	2001
Earnings (loss) from operations and net earnings (loss)	\$ (50)	\$ 79	\$ 59
Cash flow	\$ 127	\$ 196	\$ 136
Expenditures on property, plant and equipment and exploration	\$ 448	\$ 462	\$ 304
Total assets	\$ 1 746	\$ 1 473	\$ 899

2003 COMPARED WITH 2002

Oil Sands suffered a loss from operations in 2003. The loss was due to an \$82 million after-tax write off of costs related to the original Edmonton refinery conversion plan, a start-up phase operating loss from Petro-Canada's 100 per cent owned *in situ* bitumen project at MacKay River and reliability problems at Syncrude.

The contribution to earnings from Petro-Canada's 12 per cent interest in Syncrude was down from the previous year due to lower production volume and an increase in operating costs, partially offset by higher oil prices. Our share of Syncrude production averaged 25 400 b/d before royalties, down from 27 500 b/d in 2002. The volume decline was due to extended maintenance turnarounds at the Aurora mine and one of the upgrader coking units and an unscheduled turnaround on the other coking unit in the fourth quarter. Our average price realized for synthetic crude oil production in 2003 was \$42.67/bbl, up from \$40.66/bbl in 2002. Average unit operating costs increased to \$23.64/bbl in 2003, compared with \$19.50/bbl in the previous year, due to higher natural gas costs, lower production volumes and increased maintenance costs.

The MacKay River project, a steam-assisted gravity drainage (SAGD) operation, worked through technical issues during its start-up year. The operating loss in 2003 was due to a longer start-up phase than originally envisaged, which resulted in lower production and higher operating costs. A major factor was a six-week shutdown of steam generation to allow for process modifications to resolve a water treating issue. The producing formation cooled during the shutdown, further delaying the initial production build-up. In the fourth quarter, with water treatment under control, production regained momentum, rising steadily to a December average of 18 600 b/d. Reflecting the setback, bitumen production for the year was less than half of the expected volume, averaging 10 700 b/d. The average price realized for MacKay River bitumen in 2003 was \$16.69/bbl. While start-up phase operating costs averaged \$22.11/bbl in 2003, they are expected to decline going forward as performance improves and volumes grow.

Syncrude Operating and Overhead Costs

Operating and overhead costs increased due to lower reliability and production volumes.



MacKay River SAGD production ramped up in 2003.

STRATEGY

Petro-Canada's Oil Sands assets include about 300 000 net acres of leases considered prospective for *in situ* development of bitumen reserves. These are long-life resources that can deliver production for well over 30 years. Our strategy for profitable growth includes:

- Phased and integrated development of reserves, incorporating the benefits of our learnings as we go.
- Disciplined capital investment to ensure these long-life projects are value creating.

Our staged approach to development of capital-intensive Oil Sands projects ensures vigorous cost management, while allowing us to benefit from evolving technology.

Executing the strategy

Oil Sands capital expenditures of \$448 million in 2003 included \$292 million for Syncrude (mainly for the Stage 3 expansion), \$112 million for reconfiguration of the Edmonton refinery (a portion of which, relating to feedstock conversion, was written off in 2003) and \$44 million for the MacKay River *in situ* project and other Oil Sands work.

At Syncrude, progress continued on the construction of the third stage of a multi-stage expansion program. Stage 3 includes a second Aurora mine and an upgrading expansion. The Aurora 2 mine was commissioned in the fourth quarter of 2003 and is contributing to the overall bitumen supply.

At MacKay River, reliability improved significantly in the fourth quarter of 2003 and the plant is on track to reach 30 000 b/d around mid-2004. With the reservoir responding well to steam injection, we expect to sustain plateau production of 25 000 to 30 000 b/d for 25 to 30 years after accounting for turnarounds and unplanned events. Starting in 2004, a 165-megawatt co-generation facility completed by TransCanada Energy Limited will contribute to operating cost reduction, as well as increase steam capacity at MacKay River. By converting waste heat from an existing gas turbine, the co-generation facility is expected to improve overall energy efficiency and reduce MacKay River gas consumption by about 10 to 15 per cent.

Following start-up of MacKay River in 2002, our plans anticipated creation of a large-scale, fully-integrated bitumen production and refining operation centered around our best-in-class Edmonton refinery. However, over the past year, as we completed our basic engineering for conversion of the Edmonton refinery, we could foresee the same significant cost escalations as were taking place in all other large bitumen upgrading projects within the industry. Our disciplined project management processes prevented us from proceeding with the project at an uneconomic level but required the write-off against earnings of the engineering costs incurred to that date. After evaluating our options, we formulated a new, scaled-down plan for upgrading and refining oil sands feedstock at Edmonton.

The new plan retains our longer-term objective of a fully integrated bitumen production and refining operation, while also providing the flexibility to pace the upstream portion of our strategy without having to move in lockstep with refinery projects. The plan builds on the \$1.4 billion strategic investments we are already making in the refinery for long-term positioning and gasoline/diesel desulphurization. Key elements of the new plan (with new investment estimated at \$1.2 billion) include building new crude and vacuum units, expanding the capacity of the existing coker and building additional sulphur and hydrogen capability. The new configuration will allow the refinery to directly upgrade approximately 26 000 b/d of bitumen and process 48 000 b/d of sour synthetic crude oil. These lower-cost feedstocks will replace the conventional feedstock that is refined today. The refinery will also continue to process about 50 000 b/d of sweet synthetic crude through its synthetic train.

Petro-Canada has a staged and integrated approach to oil sands development.

OUTLOOK

2004 production expectations:

- Our share of Syncrude production to average 28 000 b/d.
- MacKay River bitumen production to average 25 000 b/d.

Growth plans:

- Continued participation in Syncrude Stage 3 expansion.
- Optimize reliability and performance of MacKay River.
- Continue prospect evaluation for next *in situ* bitumen project.

2004 capital spending plans:

- \$305 million for our share of Syncrude's Stage 3 expansion, sustaining capital for both Syncrude and MacKay River, delineation of future bitumen resources and other expenses.

The Syncrude upgrader expansion is behind schedule. More information on the schedule and costs to complete Stage 3 is expected in the first half of 2004. Completion of Stage 3 will enable Petro-Canada's share of Syncrude production capacity to rise by 13 000 b/d. Syncrude management continues to direct considerable resources towards improving plant reliability to secure more consistent achievement of production targets and lower unit operating costs.

Initially, on completion of the Edmonton refinery reconfiguration in 2008, Petro-Canada will fill out the refinery's bitumen processing capability through the purchase of 26 000 b/d of bitumen from other producers. This external feedstock will be replaced in due course by supply from our next *in situ* SAGD development. Another important element of our plan is an agreement with Suncor Energy Inc. that takes effect in 2008, subject to regulatory approval. Under the agreement, Suncor will process a minimum 27 000 b/d of our MacKay River bitumen production, on a fee-for-service basis, to produce an estimated 22 000 b/d of sour synthetic. This sour crude, combined with an additional 26 000 b/d of sour synthetic crude purchased from Suncor, will complete our feedstock requirements. Both the processing and sales components of the bitumen agreement will be for minimum 10-year terms.

During 2003, the federal government's implementation plan for the Kyoto Protocol became clearer. The government has given assurances that its commitment to climate change action will not jeopardize economic growth and that it understands the importance of the issue to oil sands development. Petro-Canada remains committed to seeking improvements to *in situ* technology that will further improve its energy efficiency.

As part of our revised strategy, earlier plans for development of Meadow Creek (owned 75 per cent by Petro-Canada) as our next *in situ* bitumen production project were suspended. Under the revised strategy, we believe smaller plants similar to MacKay River will enable us to leverage knowledge gained through MacKay River operations and benefit from rapidly changing technology advances. Our oil sands winter drilling evaluation program is therefore focusing on delineation of "sweet spots" at Meadow Creek and evaluation of expansion potential at MacKay River. Our revised plan anticipates our next *in situ* project coming on-stream late in this decade.

In December 2003, Petro-Canada announced a new plan to upgrade bitumen at the Edmonton refinery.

International

International Financial Results

(millions of dollars)	2003	2002	2001
Earnings (loss) from operations	\$ 297	\$ 225	\$ (27)
Gain on sale of assets	10	—	—
Net earnings (loss)	\$ 307	\$ 225	\$ (27)
Cash flow	\$ 890	\$ 583	\$ 27
Expenditures on property, plant and equipment and exploration	\$ 525	\$ 221	\$ 153
Total assets	\$ 3 883	\$ 3 544	\$ 186

2003 COMPARED WITH 2002

The solid improvement in International earnings from operations in 2003 mainly reflects an additional four months contribution from assets acquired in 2002, and higher commodity prices. Positive adjustments related to the clarification of production rights and the settlement of a tax issue associated with a former operation also contributed to the improvement.

Offsetting factors included a \$46 million impairment provision related to the impending sale of assets in Kazakhstan. This sale was completed in February 2004. Petro-Canada's International production of crude oil and natural gas in 2003 averaged 210 000 boe/d, essentially unchanged from an average of 212 000 boe/d over the last eight months of 2002.

STRATEGY

Petro-Canada's International operations are currently focused on three core exploration and production regions: Northwest Europe; North Africa/Near East; and Northern Latin America. The Company is positioning itself to become a larger international player. Our strategy is to build a platform to deliver long-term profitable growth. This strategy includes the following key elements:

- Expand and exploit the existing portfolio of assets.
- Target new theatres of operation and acquisitions.
- Develop a balanced exploration program.

Executing the strategy

Over the past two years, we have established a platform for successful international growth. In 2003, International capital expenditures amounted to \$525 million, exceeding original plans due to the acquisition of additional assets in the U.K. North Sea, partially offset by exploration program reductions and lower spending in Libya. By core area, spending totalled \$362 million in Northwest Europe, \$137 million in North Africa/Near East, and \$26 million in Northern Latin America.

Northwest Europe

In Northwest Europe, we have a solid foothold in the highly profitable North Sea with production from the U.K. and Netherlands sectors. We also have exploration programs in Denmark and the Faroe Islands. While the region is mature, we believe small- to mid-size reserves can be produced economically, especially if tied back to existing infrastructure. In 2003, Petro-Canada's production from Northwest Europe averaged 37 700 b/d of crude oil and natural gas liquids and 80 mmcf/d of natural gas, compared with averages of 40 500 b/d and 90 mmcf/d respectively over the last eight months of 2002. The lower volumes mainly reflected extended maintenance shutdowns at the Triton FPSO and Scott platform in the U.K. North Sea.

In 2003, Petro-Canada expanded its position in the U.K. North Sea through the exchange and acquisition of property interests. The property acquisitions are in and around the Triton FPSO and include increased interests in the Guillemot West and Northwest producing fields and a 100 per cent working interest in block 21/23b. This block contains the undeveloped Pict oil discovery (previously named Grebe), which is similar in size to our Clapham field (Petro-Canada – 100 per cent working interest). Development of Clapham in 2003 included the tie-back of two production and two injector wells and subsea facilities to the Triton FPSO via the Guillemot West subsea infrastructure. Field production came on stream in November and reached a planned peak of 15 000 b/d prior to year-end.

In the Netherlands sector, development of a prior year natural gas discovery on Block L5b (Petro-Canada – 30 per cent working interest) was completed ahead of schedule, with first gas on stream in October. At year-end, Petro-Canada's share of production had reached a peak of 18 mmcf/d. In a strategic realignment of our Netherlands holdings during 2003 we divested non-core acreage and acquired additional exploration assets, licences F6 and L6a, concentric to our remaining holdings and infrastructure.

North Africa/Near East

Our interests in this core region, particularly in Syria and Libya, provide a significant base of production as well as considerable re-development potential. In 2003, Petro-Canada's North Africa/Near East production of crude oil and natural gas liquids averaged 143 100 b/d and 32 mmcf/d for natural gas, compared with averages of 145 400 b/d and 44 mmcf/d, respectively, over the last eight months of 2002. The lower volumes reflected a production decline in Syria with some offset from increased volumes from Libya, including new production from the En Naga block which came on stream in February 2003.

In mid-2003, Petro-Canada, together with Syria Shell Petroleum Development B.V., finalized an agreement with the Syrian government that extends rights to deep and lateral reserves on existing acreage. The agreement supplements the three existing Production Sharing Contracts under which the companies operate, through the Al Furat Petroleum Company joint venture. The new agreement is of particular significance as production from this area will partially offset the production declines we are seeing from existing fields.

International is a
solid business focused
on three core areas.

Furthering our plans for a balanced International exploration program for longer-term growth, we have expanded our portfolio of operated exploration assets in Tunisia, Syria and Algeria. In Tunisia, subject to final government approval, we have farmed in to the 845 000-acre (3 420-square-kilometre) Melitta Exploration Permit, located mainly offshore in the Mediterranean Sea. In northeast Syria, we were awarded the 1 680 000-acre (6 800-square-kilometre) exploration Block II. In Algeria, subject to final government approval, we have been awarded the 691 000-acre (2 800-square-kilometre) Zotti 431b block, located in the Amguid Messaoud basin.

Northern Latin America

In Trinidad, Petro-Canada's 17 per cent working interest share of production from the North Coast Marine Area-1 offshore gas project averaged 63 mmcf/d before royalties, up from 32 mmcf/d for the period from start-up to the end of 2002. Natural gas is delivered to the Atlantic LNG facility at Point Fortin for liquefaction and sale into United States markets. During the second half of 2003, operating results exceeded expectations following start-up of the new Train 3. Contributing factors included better than expected productivity and performance from wells and the Hibiscus production platform, and the LNG facility, which consistently exceeded design capacity. In 2003, a successful exploration well drilled from the Hibiscus platform in 2003 was completed as a production well, providing additional gas volumes to the project.

Late in 2003, discussions concerning the potential acquisition of the Cerro Negro heavy oil assets in Venezuela were terminated, as pre-emptive rights held by other joint owners could not be resolved.

We're targeting new International opportunities to add profitable long-term growth.

OUTLOOK

2004 production expectations:

- Northwest Europe oil and gas production to average 54 000 boe/d.
- North Africa/Near East oil and gas production to average 133 000 boe/d.
- Northern Latin America natural gas production to average 60 mmcf/d.

Growth plans:

- Development of De Ruyter and Pict in the North Sea.
- Exploration in Syria, Tunisia and Algeria.
- Identify and develop growth opportunities in new areas.

2004 capital spending plans:

- \$240 million on existing assets.
- \$400 million for new developments and exploration.

Planned expenditures on existing assets in 2004 will focus primarily on Syria, Libya and the U.K. New development investments will include Pict in the U.K. and De Ruyter in the Netherlands. In Venezuela, an extended production test will be undertaken to evaluate the commercial viability of the La Ceiba crude oil discovery (Petro-Canada – 50 per cent working interest). Exploration and new venture plans anticipate work on Block II in Syria, Melitta in Tunisia, Zotti in Algeria and concentric exploration associated with existing ventures.

Reserves Inventory

Our large reserves inventory provides a strong base for future growth.



■ Proved reserves
(millions of barrels of
oil equivalent)

**Petro-Canada
reserves processes
and estimates
are audited
by independent
consultants.**

RESERVES

At year-end 2003, proved reserves before royalties (including synthetic crude oil from oil sands mining) totalled 1 220 million barrels of oil equivalent (mmboe), down five per cent from a year earlier. As part of our long-term reserves replacement strategy, we have added exploration capability and funding – especially internationally – to develop a balanced exploration program aimed at increasing our reserves base over time. In particular, we will target long-life reserves and aim for greater Petro-Canada operatorship. Our goal is a growth portfolio that provides a balanced range of risk/reward opportunities. The new exploration acreage recently acquired in Syria, Tunisia and Algeria are early examples of initiatives in the International business. In Canada, Petro-Canada continues to pursue opportunities off the East Coast and North of 60 while in Western Canada, we plan to gradually increase our exploration program over time to improve reserves replacement.

In order to harmonize its oil and gas disclosure in both Canada and the U.S., Petro-Canada applied for, and received, certain exemptions to reserves disclosure requirements as set out in National Instrument 51-101; *Standards of Disclosure for Oil and Gas Activities* (NI 51-101), which was adopted in 2003 by the securities regulatory authorities in Canada. These exemptions permit Petro-Canada to use its own staff of qualified reserves evaluators to prepare the Company's reserves estimates and to use U.S. Securities Exchange Commission (SEC) and Financial Accounting Standards Board (FASB) standards when reporting reserves.

Petro-Canada strongly believes that its use of its own staff of qualified reserves evaluators who are familiar with the Company's oil and gas assets as a result of working with them on a day-to-day basis, combined with independent third party evaluation/audit of both its reserves processes and its reserves estimates, provides a level of confidence in its reserves data that is at least as good as would be provided if the work was done solely by a third party.

Petro-Canada's staff of qualified reserves evaluators determine the Company's reserves data and reserves quantities based on corporate-wide policies, procedures and practices. These reserves policies, procedures and practices conform with the requirements of Canadian as well as SEC regulations and the Association of Professional Engineers, Geologists and Geophysicists of Alberta Standard of Practice for the Evaluation of Oil and Gas Reserves for Public Disclosure. To confirm the quality of the reserves policies, procedures and practices and the internally-generated reserves estimates, Petro-Canada employs the services of independent engineering evaluators/auditors. During 2003, independent petroleum reservoir engineering consultants Sproule Associates Limited (Sproule) and Gaffney, Cline & Associates Ltd. (GCA) conducted evaluations, technical audits and reviews of Petro-Canada's hydrocarbon reserves. GCA completed an independent audit of 70 per cent of the Company's proved crude oil, natural gas and natural gas liquids reserves outside of Canada. Similarly, Sproule audited Petro-Canada's proved oil and gas reserves estimates for Hibernia and Terra Nova, evaluated 54 per cent of Western Canada proved conventional oil and gas reserves and reviewed the balance of Western Canada, White Rose and Syncrude. The independent auditors'/evaluators' reports concluded that the Company's year-end 2003 proved reserves estimates are reasonable.

Sproule and GCA also audited Petro-Canada's reserves policies, procedures and practices and concluded that Petro-Canada's reserve booking standards meet applicable disclosure regulations, that management is complying with those standards and the reserves process is performed in a manner and standard consistent with the auditors' practices. In addition, PricewaterhouseCoopers LLP, as contract internal auditor, tested the non-engineering management control processes used in establishing reserves.

Detailed information about Petro-Canada's reserves of crude oil, natural gas liquids, natural gas, bitumen and synthetic crude oil is available on pages 60-63 of this Annual Report.

DOWNSTREAM

Our Downstream operations include three refineries with a total rated capacity of 49 800 cubic metres (313 000 barrels) per day, and a lubricants plant that is the largest producer of lubricant base stocks in Canada and the largest producer of white oils in the world. In 2003, Petro-Canada accounted for about 17 per cent of the Canadian industry's total refining capacity and our product sales represented about 17 per cent of total petroleum products sold in Canada.

Downstream Financial Results

(millions of dollars)

	2003	2002	2001
Earnings from operations	\$ 264	\$ 254	\$ 300
(Loss) gain on sale of assets	(15)	3	1
Net earnings	\$ 249	\$ 257	\$ 301
Cash flow	\$ 601	\$ 380	\$ 589
Expenditures on property, plant and equipment	\$ 424	\$ 344	\$ 383
Total assets	\$ 3 838	\$ 3 841	\$ 3 556

2003 COMPARED WITH 2002

Downstream financial performance in 2003 reflected improved revenues from higher cracking margins, lower income taxes, and a one-time charge for a refinery closure.

The lower income taxes reflect a \$34 million net positive adjustment resulting primarily from changes in income tax rates. The one-time charge for the refinery closure, amounting to \$151 million after tax, relates to the planned closure of Petro-Canada's Oakville refinery. Net earnings of \$249 million in 2003 are after deduction of a \$15 million loss on asset sales mainly related to the selective rationalization of marketing networks in Eastern Canada. The increase in cash flow reflects the higher earnings before the non-cash charge for Oakville and lower current taxes resulting from the inventory accounting method required for income tax purposes. This method resulted in a \$25 million decrease in current taxes in 2003, compared with an \$85 million increase in 2002.

Strong performance in Refining and Supply mainly resulted from higher refinery crack spreads and wider light/heavy crude oil price differentials, which more than offset the effects of a one per cent decline in overall crude capacity utilization at our three refineries. Total crude oil processed in 2003 averaged 49 900m³/d, down from 50 400 m³/d in 2002. The decline reflected unplanned shutdowns and the impact on the Oakville refinery of a major power outage in Ontario in August.

Sales and Marketing results also improved, as sales of refined products, boosted by strong wholesale distillate sales, increased to a record 56 800 cubic metres per day (m³/d) from 55 700 m³/d in 2002. Additionally, the contribution from non-petroleum product sales continued to demonstrate strong growth with convenience store sales rising 16 per cent from the previous year. The strong performance was achieved despite a challenging business environment for much of the year, including concerns over SARS, which reduced travel in important urban markets, the power outage in Ontario and problems in the beef and lumber industries that affected distillate sales. Additionally, high crude prices continued to place considerable pressure on product margins. Total Downstream operating, marketing and general unit costs, at 6.3 cents per litre, were up from 5.8 cents per litre in 2002. The increase mainly reflected the de-commissioning and employee-related costs associated with the planned closure of the Oakville refinery, and a partial shutdown of the Lubricants plant following the August power outage.

Downstream Operating, Marketing and General Costs

Per-litre costs reflected increased costs for the planned closure of the Oakville refinery and the incident at the Lubricants plant.



■ Unit operating, marketing and general costs (cents per litre)

STRATEGY

Our Downstream strategies are focused on strengthening the foundations for improved profitability through effective capital investment and discipline over controllable factors. Our goal is superior returns and growth, including a minimum 12 per cent return on capital employed, based on a mid-cycle business environment.

Key features of our strategy include:

- Achieving and maintaining first-quartile operating performance.
- Advancing Petro-Canada as the brand of choice for Canadian gasoline consumers.
- Building on our marketplace strengths and increasing sales of high-margin specialty lubricants.

In September 2003, Petro-Canada announced the planned closure of the Oakville refinery.

Refinery Utilization

Lower refinery utilization was due to unplanned shutdowns.



Our rated refinery crude capacity was increased in 2001 following process improvements.

Executing the strategy

In 2003, Petro-Canada advanced two key strategic initiatives that will position Refining and Supply operations for long-term profitability.

In the third quarter of 2003, plans were finalized for the consolidation of our Eastern Canada refining operations at the Montreal refinery. These plans include shutting down the Oakville refinery by the end of 2004 and expanding the existing Oakville terminal facilities and the Montreal refinery. The changes will enable the transition from a refining-focused operation to a supply and logistics centered function where best-in-class performance is achievable. We will complete the project in time to meet compliance with federal legislation lowering limits for sulphur in gasoline, effective January 1, 2005.

The second key initiative is a new plan for upgrading and refining oil sands feedstock at our Edmonton refinery. Details are outlined in the Oil Sands section of this MD&A.

Plant reliability, a critical component of success in the refining business, fell below our target in 2003, due to unplanned shutdowns at our refineries and Lubricants plant. Going forward, we will intensify our efforts to optimize operations and maintenance procedures to achieve first quartile performance based on Solomon & Associates benchmarking. As part of our efforts to reduce costs and greenhouse gas emissions, we remain committed to reduce energy consumption by an average of one per cent per year through 2005.

Downstream capital expenditures on property, plant and equipment were \$424 million in 2003, marginally below plan as reduced spending on the Oakville refinery was essentially offset by acquisitions in the home heating business. A major portion of 2003 spending was directed at meeting the federal regulatory requirement of 30 parts per million of sulphur in gasoline by 2005. The new gasoline desulphurization unit at the Montreal refinery was completed and successfully commissioned in the fourth quarter of 2003. Construction of the Edmonton gasoline desulphurization unit is ongoing and it will be operational ahead of the legislated date.

In Sales and Marketing, we continued to take steps to grow the profitability of our retail network by focusing on two key areas. The first involved leveraging all aspects of the Petro-Canada brand and product service to be the brand of choice for Canadians. In 2003, this resulted in:

- 16 per cent overall growth in convenience store sales (including nine per cent growth in same store sales)
- 10 per cent growth in the number of Petro-Points loyalty program members; and
- the growing success of our first-in-the-industry prepaid card program, particularly in the business to business segment.

Secondly, we focused on achieving appropriate Petro-Canada representation to generate high site throughputs and profitable share of market. In 2003, this resulted in the sale of Petro-Canada's Newfoundland and Labrador retail network and the selective rationalization of our Eastern Canada retail network. The impact of reduced product sales resulting from these divestitures was offset by growth initiatives such as the continued roll-out of Petro-Canada's successful new-image service stations. At year-end, the program of converting all Company-controlled sites that meet our economic return criteria was about 80 per cent complete. Significant progress was also made in the number of independent retailers participating in the new-image program. About 40 per cent of our retail sites are independent and, at year-end, over 30 per cent of these retailers were operating with the new-image standard. This program has been instrumental in driving incremental increases in throughputs and profitability. In 2003, total throughput from our retail network of 1 432 sites averaged 4.2 million litres per site, compared with 4.1 million litres in the previous year. Average annual throughputs from re-imaged sites averaged in excess of seven million litres, representing a significant competitive advantage.

In the Wholesale business, the focus has been on growing profitably in high-value channels. Examples include acquisitions in the home heat business in Ontario and the launch of a new innovative product in Eastern Canada called ThermaClean®, a higher-value proprietary furnace fuel that helps lessen the impact of home heating on the environment while helping prolong furnace life. In the commercial road transport business, Petro-Canada is maintaining its best-in-class position. With our Petro-Pass network of 210 truck stop facilities and our premiere fleet management card, Petro-Canada is the market leader in serving Canada's commercial road transport industry. In 2003, we focused on enhancing our leadership position by further upgrading our network and increasing volume through sales efforts in this high-value channel.

In Lubricants, financial performance in 2003 was impacted by a difficult business environment, including softness in some key export markets, particularly the United States where a weak economy dampened sales. Other factors included high natural gas prices and the regional power outage in August.

Product Sales

Total Downstream sales per retail site continued to grow in 2003.



While Lubricants sales in 2003 were unchanged from the 768 million litres achieved in 2002, the high-margin product component rose five per cent, reflecting strong growth in automotive sales, drilling industry sales and higher-value base oils. At year-end, high-margin sales accounted for over 65 per cent of total lubricants sold. About two-thirds of our manufactured lubricants, specialty fluids and greases are currently sold outside of Canada. We continue to target accelerated growth in international markets to take advantage of increasing global demand for higher-quality base oils. An improving high-margin sales mix, cost-reduction initiatives in the areas of energy and distribution, and delivery on plans to achieve efficient and reliable plant operations will position Lubricants for continued profitable growth.

In 2004 we will focus on improving plant reliability.

OUTLOOK

Growth plans:

- Improve plant reliability.
- Implement key strategic initiatives in Refining and Supply.
- Secure further reductions in operating costs.
- Maximize benefits from retail site re-imaging program.
- Capitalize on the increasing demand for higher quality base oils.

2004 capital spending plans:

- \$705 million for Refining and Supply.
- \$150 million for Sales and Marketing.
- \$10 million for Lubricants.

While a substantial portion of our planned Downstream investments in 2004 will be directed towards lessening the environmental impact of our operations and products, we remain focused on positioning Petro-Canada for improved profitability. Estimated capital expenditures for Refining and Supply include about \$445 million for refinery reconfigurations to meet new lower limits for sulphur in gasoline and diesel at our Edmonton and Montreal locations; about \$135 million to consolidate our Eastern Canada refinery operations at Montreal, including the conversion of our Oakville facility; and \$50 million for engineering, site preparation and other costs associated with the new feedstock conversion plans for the Edmonton refinery. Sales and Marketing expenditures include \$100 million for retail growth initiatives, including the continued roll-out of the new-image service station program, and \$30 million for wholesale growth initiatives to further develop our Petro-Pass network.

SHARED SERVICES

Shared Services include investment income, interest expense, foreign currency translation and general corporate revenue and expenses.

Shared Services Financial Results

(millions of dollars)	2003	2002	2001
Net expenses from operations	\$ (182)	\$ (144)	\$ (51)
Foreign currency translation	239	(52)	(96)
Gain on sale of assets	1	—	—
Net earnings (expense)	\$ 58	\$ (196)	\$ (147)
Cash flow	\$ (100)	\$ (104)	\$ (53)

2003 COMPARED WITH 2002

The rise in net expenses from operations in 2003 primarily reflects higher income taxes including increases resulting from changes in federal and provincial income tax rates. The 2003 foreign currency translation gain on U.S. dollar-denominated long-term debt reflects the significant improvement in the strength of the Canadian dollar versus the U.S. dollar. The foreign currency translation loss of \$52 million in 2002 includes a one-time \$63 million exchange loss from the translation of the International business segment and an \$11 million gain on translation of U.S.-dollar-denominated debt.

LIQUIDITY AND CAPITAL RESOURCES

Summary of Cash Flows

(millions of dollars)	2003	2002	2001
Net cash inflows (outflows) before changes in non-cash working capital:			
Cash flow	\$ 3 372	\$ 2 276	\$ 1 688
Investing activities	(2 297)	(4 141)	(1 564)
Financing activities	(604)	1 560	(909)
	471	(305)	(785)
(Increase) decrease in non-cash working capital and other	(70)	(242)	151
Increase (decrease) in cash and cash equivalents	\$ 401	\$ (547)	\$ (634)
Cash and cash equivalents at end of year	\$ 635	\$ 234	\$ 781

OPERATING ACTIVITIES

The improvement in cash flow before changes in non-cash working capital to \$3 372 million in 2003 resulted primarily from higher commodity prices, production gains and improved refinery crack spreads, partially offset by an increase in current income taxes. The reduced cash outflow on investing activities reflects the acquisition of oil and gas assets from Veba Oil & Gas GmbH in 2002. The net cash outflow on financing activities in 2003 results primarily from the repayment of a substantial portion of the credit facility set up to finance the Veba acquisition.

The \$70 million increase in non-cash operating working capital reflects decreases in accounts payable and accrued liabilities and the current portion of long-term liabilities partially offset by a decrease in accounts receivable and an increase in income taxes payable.

INVESTING ACTIVITIES

Capital and Exploration Expenditures

(millions of dollars)	2003	2002	2001
Upstream¹			
North American Gas	\$ 560	\$ 530	\$ 548
East Coast Oil	344	289	279
Oil Sands	448	462	304
International	525	221	153
	1 877	1 502	1 284
Downstream			
Refining and Supply	296	210	206
Sales and Marketing	117	118	156
Lubricants	11	16	21
	424	344	383
Shared Services	14	15	14
Total property, plant and equipment and exploration	2 315	1 861	1 681
Deferred charges and other assets	147	72	10
Acquisition of oil and gas operations of Veba Oil & Gas GmbH	–	2 234	–
Total	\$ 2 462	\$ 4 167	\$ 1 691

¹ Includes exploration expenses charged to earnings, totalling \$271 million in 2003, \$301 million in 2002 and \$245 million in 2001.

Petro-Canada has the financial strength and flexibility to pursue new opportunities.

Petro-Canada's substantial capital spending on property, plant and equipment and exploration in 2003 reflects our commitment to long-term profitable growth and added value for shareholders. The 24 per cent increase in expenditures to \$2 315 million in 2003, primarily reflects an additional four months of major international activity, the White Rose development and increased spending in the Downstream to meet lower limits for sulphur in gasoline. The increase in deferred charges and other assets includes higher corporate expenditures resulting from the issuance and interest hedging costs associated with the placement of U.S. dollar-denominated long-term debt.

Planned investments for 2004, totalling \$2 645 million, reaffirm our growth commitment. Upstream expenditures are estimated at \$1 765 million, with \$495 million allocated to North American Gas, \$325 million to East Coast Oil, \$305 million to Oil Sands and \$640 million to International. Planned Downstream expenditures amount to \$865 million, with \$705 million for Refining and Supply, including a recent \$50 million addition for anticipated spending on new feedstock conversion plans for the Edmonton refinery, \$150 million for Sales and Marketing and \$10 million for Lubricants. Additionally, \$15 million is provided for corporate and other purposes. We plan to fund the 2004 capital expenditure program from cash flow.

Capital investments are forecast to be \$2 645 million in 2004.

FINANCING ACTIVITIES AND DIVIDENDS

Sources of Capital Employed

<i>(millions of dollars)</i>	2003	2002	2001
Long-term debt, including current portion	\$ 2 229	\$ 3 057	\$ 1 401
Shareholders' equity	7 721	5 776	4 877
Total	\$ 9 950	\$ 8 833	\$ 6 278

The decrease in total debt to \$2 229 million at December 31, 2003, compared with \$3 057 million the previous year-end, reflects \$548 million of net debt repayments and a \$280 million reduction due to the revaluation of U.S. dollar denominated long-term debt. During the year 2002, the Company borrowed \$2 100 million, by way of an acquisition credit facility, to finance the funding of the purchase of the upstream assets of Veba Oil & Gas GmbH. During 2002, the Company repaid \$461 million from cash flow. During 2003, a further \$542 million was repaid from cash flow and \$804 million was refinanced by way of a long-term debt offering completed in June 2003.

In 2003, we repaid \$548 million of debt.

Debt Offering – June 2003

Purpose of offering:	To repay bank indebtedness incurred in the acquisition of oil and gas operations from Veba Oil & Gas GmbH
Size of offering:	US\$600 million
Form of securities:	US\$300 million of 4.00% Notes and US\$300 million of 5.35% Notes
Net proceeds of issue:	US\$592 million
Application of proceeds:	Reduction of short-term, floating rate acquisition credit facility

The following table summarizes Petro-Canada's contractual obligations as at December 31, 2003.

Contractual Obligations – Summary

(millions of dollars)

	Total	PAYMENTS DUE BY PERIOD			
		2004	2005-2006	2007-2008	2009 and thereafter
Unsecured debentures and notes ¹	\$ 1 842	\$ –	\$ –	\$ –	\$ 1 842
Acquisition credit facility ¹	293	–	293	–	–
Capital lease obligations ²	94	6	15	10	63
Operating leases	687	115	168	129	275
Transportation agreements	1 357	158	302	246	651
Product purchase/delivery obligations ²	1 216	70	150	150	846
Exploration work commitments ³	71	36	27	8	–
Other long-term obligations ^{4,5}	102	82	4	2	14
Total contractual obligations	\$ 5 662	\$ 467	\$ 959	\$ 545	\$ 3 691

- Obligations exclude related interest. For further details see Note 16 to the 2003 Consolidated Financial Statements.
- Excludes supply purchase agreements that are contracted at market prices where the products could reasonably be resold into the market.
- Excludes other amounts related to the Company's expected future capital spending. Capital spending plans are reviewed and revised annually to reflect the Company's strategy, operating performance and economic conditions. For further information regarding future capital spending plans refer to the business segment and investing activities discussions in the previous sections of the 2003 MD&A.
- Includes pension funding obligations for the periods prior to the Company's next required pension plan valuation. Obligations beyond the next required valuation date have been excluded due to the uncertainty as to the amount or timing of these obligations.
- The Company is involved in litigation and claims associated with normal operations. Management is of the opinion that any resulting settlements would not materially affect the financial position of the Company. The table excludes amounts for these contingencies due to the uncertainty as to the amount or timing of any settlements.

Petro-Canada plans to meet remaining debt repayment commitments out of a combination of cash flow and debt financing.

As a result of the substantial debt reduction in 2003, our financial ratios have returned to pre-acquisition levels, providing expanded financial capacity to fund continued growth and new opportunities.

Financial Ratios

	2003	2002	2001
Interest coverage (times):			
Earnings basis	16.7	10.5	9.7
EBITDAX basis	26.3	17.1	15.1
Cash flow basis	25.4	17.9	15.6
Debt to cash flow (times)	0.7	1.3	0.8
Debt to debt plus equity (per cent)	22.4	34.6	22.3

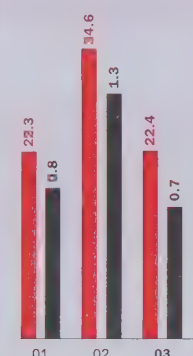
Petro-Canada's debt to cash flow ratio, our key short-term leverage measure, strengthened to 0.7 times at December 31, 2003, compared with 1.3 times at the end of 2002. We expect to remain well within our target range of no more than 2.0 times through 2004. Debt to debt plus equity, our long-term measure for capital structure, improved to 22.4 per cent from 34.6 per cent at the prior year-end. Our target range is from 25 to 30 per cent. Petro-Canada has controls in place to ensure compliance with all financial covenants.

For operating purposes, Petro-Canada had cash and cash equivalents of \$635 million and undrawn committed bank credit facilities totalling \$1 159 million at 2003 year-end. Petro-Canada will continue to use its cash position and will draw on bank lines and issue commercial paper if necessary to meet working capital and other financing requirements.

The Company's unsecured long-term debt securities are rated Baa2 by Moody's Investors Service, BBB by Standard & Poor's Rating Services and A (low) by Dominion Bond Rating Service. The Company's long-term debt ratings remain unchanged from year-end 2002.

Key Debt Ratios

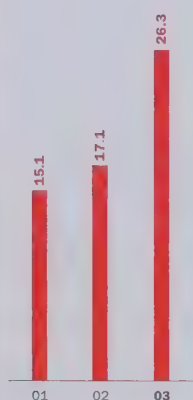
With the repayment of \$548 million of debt in 2003, the Company is well positioned relative to its target levels.



■ Debt to debt plus equity (per cent)
■ Debt to cash flow (times)

Interest Coverage

A positive interest coverage ratio demonstrates more than sufficient earnings to cover interest charges on debt.



■ Interest coverage ratio (times)
– Calculated on an EBITDAX basis.

Excluding cash and cash equivalents and the current portion of long-term debt, Petro-Canada had an operating working capital deficiency of \$52 million at the end of 2003 compared with operating working capital of \$36 million as at December 31, 2002.

Petro-Canada does not currently have any off-balance sheet accounting in place to structure any of its financial arrangements. Off-balance sheet activities are limited to matters such as guarantees, none of which would have a material impact on the Company's financial results, liquidity or capital resources.

At 2003 year-end, Petro-Canada's defined benefits pension plans were under-funded by \$292 million, compared with an under-funded position of \$279 million at the end of 2002. In 2003, Petro-Canada made cash contributions of \$86 million to the pension plans and recorded a pension expense of \$72 million before tax. This compares with \$22 million and \$28 million, respectively, for 2002. In 2004, the Company expects to make a contribution of approximately \$86 million and record an expense of about \$65 million.

Petro-Canada reviews its dividend strategy from time to time to ensure the alignment of dividend policy with shareholder expectations and our financial and growth objectives. Currently, our first priority for available cash is to fund growth opportunities. Our second priority is to return funds to shareholders. In 2003, when the quarterly dividend was \$0.10 per share, Petro-Canada paid \$106 million in dividends, compared with \$105 million in 2002. The quarterly dividend payable on April 1, 2004, to shareholders of record on March 3, 2004, has been increased to \$0.15 per share.

Petro-Canada
announced a
50 per cent dividend
increase in
January 2004.

RISK MANAGEMENT

Petro-Canada's results are impacted by management's strategy for handling risks inherent in the underlying business, which fall into four broad categories: business risks; operational risks; political risks; and market risks.

Management believes each major risk requires a unique response within our broad business strategy and Petro-Canada's financial tolerance. While some risks can be effectively managed through internal controls and business processes, others are managed through insurance. The Audit, Finance and Risk Committee of the Board of Directors has oversight responsibility for risk management. The following describes Petro-Canada's approach to managing major risks.

BUSINESS RISKS

Exploration

Petro-Canada's future cash flows are highly dependent on our ability to replace natural decline as reserves are produced. Reserves can be added through successful exploration or acquisition. However, as basins mature, replacement of reserves becomes more challenging and expensive, and we may choose to allow reserves to decline in some areas if replacement is uneconomic. Petro-Canada maintains an extensive exploration program in Canada and internationally. To support this program, we have entered into a variety of alliances with world-class suppliers. These alliances provide preferential access to equipment, labour and advanced technology at competitive prices. There is no assurance that we will successfully replace all reserves in any given year.

Reserve Estimates

Estimates of economically recoverable oil and gas reserves are based upon a number of variables and assumptions such as geoscientific interpretation, commodity prices, operating and capital costs, and production forecasts, all of which may vary considerably from actual results.

Project Execution

Petro-Canada manages a variety of small and large projects in support of continuing operations and future growth. Many project risks, such as those involving material costs, labour productivity, timely availability of skilled labour, and currency fluctuations are influenced by external factors beyond our control. Petro-Canada is enhancing its project management capability. We have built on our experience in major project development to establish effective standardized processes, backed by well-trained people, to manage projects across the organization. The goal is to consistently and predictably deliver projects on time, on budget, and achieve defined expectations, thereby improving all elements of project execution including safety and environmental performance, quality, cycle time and cost.

Third Party Operator

Other companies may manage construction or operation of assets in which Petro-Canada has an interest. The Company has limited ability to exercise influence over operations of these assets or their associated costs, which could adversely affect financial performance.

Environmental Regulations

Environmental risks inherent in the oil and gas industry are increasingly significant as related laws and regulations become more stringent in Canada and other countries where Petro-Canada operates. Increased regulations may require the Company to invest additional capital to satisfy new product specifications or address environmental issues, increase operating costs by reducing the yield of desirable products, or create a future liability for dismantling and remediating production facilities.

Petro-Canada conducts Life-Cycle Value Assessment (LCVA) to integrate and balance environmental, social and economic decisions related to major projects. A key component of the LCVA process is to include in front-end planning all life-cycle stages involved in constructing, manufacturing, distribution and eventually abandoning an asset or a product. This process encourages more comprehensive exploration for alternatives. Although LCVA is a useful technique, it relies on the current regulatory regime or one that can be reasonably expected.

Government Regulations

The Company is subject to regulation and intervention by governments in such matters as contracting of exploration and production interests, imposition of specific drilling obligations, and possibly expropriation or cancellation of contract rights. As well, governments may regulate or intervene with respect to price, taxes, royalties and exploration. The Company has limited ability to influence these regulations and they may have a material adverse effect on the Company.

Counter-parties

In the normal course of business, Petro-Canada is exposed to credit risk resulting from the uncertainty of a counter-party's ability to fulfil an obligation in accordance with the terms and conditions of a contract. To minimize credit exposure, we have established internal credit policies and procedures that include financial assessments, exposure limits and processes to monitor the exposures against these limits. Where appropriate, we use netting and collateral arrangements to minimize risk.

Petro-Canada only transacts derivatives with counter-parties who possess a minimum long-term credit rating of A (unless otherwise approved by the Board) under a signed International Swap Dealers Association agreement. Credit limits take into account both current and potential exposure to a counter-party and limit concentration of risk.

OPERATIONAL RISKS

Production, refining, transporting and marketing oil and gas involve significant operational hazards. We manage operational risks primarily through our integrated Total Loss Management (TLM) system and a Corporate Insurance Program. TLM is an internally developed management system with standards for preventing operational incidents. A program of regular TLM audits tests compliance to the standards. The Corporate Insurance Program transfers some operational risks to third party insurers worldwide. Limits of insurance are based on financial quantification of a 'maximum foreseeable exposure' related to major assets. Petro-Canada optimizes the program by evaluating deductibles, limits and coverage. The Company's financial tolerance to withstand the impact of a major isolated event may be utilized to manage total premium cost. Although Petro-Canada maintains insurance in accordance with customary industry practices, we cannot fully insure against all risks. Losses resulting from operational incidents could have a material adverse impact on the Company.

POLITICAL RISKS

Internationally, Petro-Canada operates in numerous countries with differing political, economic and social systems. Our operations and related assets are subject to the risks of actions by governmental authorities, insurgent groups or terrorists. Additionally, Petro-Canada operates in OPEC-member countries and production in those countries may be constrained from time to time by OPEC quotas. We evaluate our exposure in any one country in the context of the Company's total operations, may limit investment to avoid excessive exposure in any one country or region and may choose not to invest in a country based on our assessment of risk.

MARKET RISKS

Commodity Prices

A significant market risk exposure for Petro-Canada is the commodity price of crude oil, refined products and natural gas. International commodity prices are volatile and are influenced by factors such as supply and demand fundamentals, geo-political events, OPEC decisions and weather. Refining margins are affected by North American supply and demand fundamentals and crude oil prices. These risks may be positive in a higher-price environment and negative in a lower-price environment.

Petro-Canada is generally averse to hedging large volumes of production. Management believes commodity prices go through price swings that are difficult to predict. We manage the business so that the Company can withstand the impact of a lower price environment, and is also fully exposed to capturing significant upside when the price environment is higher. However, commodity prices and margins may be hedged occasionally to capture opportunities that represent extraordinary value. Certain Downstream physical transactions are routinely hedged for operational needs and to facilitate sales to customers.

Foreign Exchange

As energy commodity prices are primarily priced in U.S. dollars, a large portion of Petro-Canada's expense and revenue stream is affected by the U.S. dollar/Canadian dollar exchange rate. Although there is a significant natural offset to this exposure as a result of our integrated business, on a net basis Petro-Canada's earnings are negatively affected by a strengthening Canadian dollar. We do not hedge this exposure, but it is partially mitigated by issuing U.S. dollar-denominated long-term debt. Foreign exchange exposure related to asset acquisitions or divestitures, or project capital expenditures, may be hedged on a case-by-case basis. Petro-Canada is also exposed to fluctuations in other foreign currencies such as the euro and British pound.

Interest Rates

Petro-Canada targets a blend of fixed and floating rate debt that enables the Company to take advantage of generally lower interest rates on floating debt while generally matching overall debt maturity with the life of cash generating assets. The Company is exposed to fluctuations in the rate of interest it pays on floating rate debt. Management's perspective is that this interest rate exposure is consistent with industry practice and it is within the Company's risk tolerance.

FINANCIAL INSTRUMENTS

Petro-Canada's market risk and derivative policy prohibits the use of derivative instruments for speculative purposes. Petro-Canada uses derivatives primarily to hedge physical transactions for operational needs and to facilitate sales to customers. The gains and losses associated with these financial instruments essentially offset gains and losses on the physical transactions. Except as specifically authorized by the Board of Directors, the term of hedging instruments cannot exceed 18 months. Monitoring and reporting of the derivatives portfolio includes periodic testing of the fair value of all outstanding derivatives. Fair values are determined by obtaining independent third party quotes for the value of each derivative instrument. The objectives and strategies of all hedge transactions are documented, as well as an assessment of the effectiveness of the derivative instrument in offsetting a change in the value of the hedged exposure.

In 2003, commodity, currency and interest rate hedges resulted in a net decrease in earnings of about \$30 million after tax, compared with a net decrease in earnings of about \$22 million in 2002. As at December 31, 2003, crude oil and natural gas contracts had been bought forward to mitigate exposure on fixed-price natural gas and refined product sales. Short-term hedge positions were also in place for refining supply and product purchases. At year end, these instruments had a fair value of \$9 million. In accordance with our derivative accounting policy, this value has been deferred and will be recognized in the period in which the derivative instrument is realized.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Company's financial statements requires management to adopt accounting policies that involve the use of significant estimates and assumptions. These estimates and assumptions are developed based on the best available information and are believed by management to be reasonable under the existing circumstances. New events or additional information may result in the revision of these estimates over time. The Audit, Finance and Risk Committee regularly reviews the Company's critical accounting policies and any significant changes thereto. A summary of the significant accounting policies used by Petro-Canada can be found in Note 1 to the 2003 Consolidated Financial Statements. The following discussion outlines what management believes to be the most critical accounting policies involving the use of significant estimates or assumptions.

PROPERTY, PLANT AND EQUIPMENT/DEPRECIATION, DEPLETION AND AMORTIZATION

Investments in exploration and development activities are accounted for under the successful efforts method. Under this method, the acquisition costs of unproved acreage, the costs of exploratory wells pending determination of proved reserves, the costs of wells which are assigned proved reserves, and development costs including costs of all wells are capitalized. The cost of unsuccessful wells and all other exploration costs, including geological and geophysical costs, are charged to earnings as incurred. Capitalized costs of oil and gas producing properties are depreciated and depleted using the unit of production method based upon estimated reserves (see Estimated Oil and Gas Reserves discussion below). Reserve estimates can have a significant impact on net earnings, as they are a key component in the calculation of depreciation and depletion related to the capitalized costs of property, plant and equipment. A revision in reserve estimates could result in either a higher or lower depreciation and depletion charge to net earnings. A downward revision in reserves could result in a writedown of oil and gas producing properties as part of the impairment assessment (see Asset Impairment discussion below).

FUTURE REMOVAL AND SITE RESTORATION COSTS

The Company currently provides for estimated future removal and site restoration costs which are probable and can be reasonably determined on either the unit of production method or the straight line method based on estimated service lives of the related assets as appropriate. Future removal and site restorations costs for inactive Downstream sites, net of expected recoveries, are provided for at the time a decision is made to decommission the site. Factors that can affect the provision include the expected costs and the estimated reserves (see Estimated Oil and Gas Reserves discussion below). Cost estimates

are influenced by factors such as the number and type of sites subject to removal and restoration, the extent of site restoration work required and changes in environmental legislation. A revision to the estimated costs or reserves could result in an increase or decrease in future removal and site restoration costs charged to net earnings.

ASSET IMPAIRMENT

Producing properties and significant unproved properties are assessed annually, or as economic events dictate, for potential impairment. Impairment is assessed by comparing the estimated undiscounted future cash flows to the carrying value of the asset. The cash flows used in the impairment assessment require management to make assumptions and estimates about recoverable reserves (see Estimated Oil and Gas Reserves discussion below), future commodity prices and operating costs. Changes in any of the assumptions, such as a downward revision in reserves, a decrease in future commodity prices, or an increase in operating costs could result in an impairment of an asset's carrying value.

PURCHASE PRICE ALLOCATION

Business acquisitions are accounted for by the purchase method of accounting. Under this method, the purchase price is allocated to the assets acquired and the liabilities assumed based on the fair value at the time of the acquisition. The excess purchase price over the fair value of identifiable assets and liabilities acquired is goodwill. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of property, plant and equipment acquired generally require the most judgement and include estimates of reserves acquired (see Estimated Oil and Gas Reserves discussion below), future commodity prices, and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities, and goodwill in the purchase price allocation. Future net earnings can be affected as a result of changes in future depreciation and depletion, asset impairment or goodwill impairment.

GOODWILL IMPAIRMENT

Goodwill is subject to impairment tests annually, or as economic events dictate, by comparing the fair value of the reporting unit to its carrying value, including goodwill. If the fair value of the reporting unit is less than its carrying value, a goodwill impairment loss is recognized as the excess of the carrying value of the goodwill over the fair value of the goodwill. The determination of fair value requires management to make assumptions and estimates about recoverable reserves (see Estimated Oil and Gas Reserves discussion below), future commodity prices, operating costs, production profiles, and discount rates. Changes in any of these assumptions, such as a downward revision in reserves, a decrease in future commodity prices, an increase in operating costs or an increase in discount rates could result in an impairment of all or a portion of the goodwill carrying value in future periods.

ESTIMATED OIL AND GAS RESERVES

Reserves estimates, although not reported as part of the Company's financial statements, can have a significant effect on net earnings as a result of their impact on depreciation and depletion rates, future removal and site restoration provisions, asset impairments, and goodwill impairment (see discussion of these items above). The Company's staff of qualified reserves evaluators performs internal evaluations on all of its oil and gas reserves on an annual basis using corporate-wide policies, procedures and practices. Independent petroleum reservoir engineering consultants also conduct annual evaluations, technical audits and reviews of a significant portion of the Company's reserves. In addition, the Company's contract internal auditor tests the non-engineering management control processes used in establishing reserves. However, the estimation of reserves is an inherently complex process requiring significant judgment. Estimates of economically recoverable oil and gas reserves are based upon a number of variables and assumptions such as geoscientific interpretation, commodity prices, operating and capital costs and production forecasts, all of which may vary considerably from actual results. These estimates are expected to be revised upward or downward over time, as additional information such as reservoir performance becomes available, or as economic conditions change.

EMPLOYEE FUTURE BENEFITS

The Company maintains defined benefit pension plans and provides certain post-retirement benefits to qualifying retirees. Obligations under employee future benefits plans are recorded net of plan assets where applicable. The cost of pension and other post-retirement benefits are actuarially determined by an independent actuary using the projected benefit method prorated based on service. The determination of these costs requires management to estimate or make assumptions regarding the expected plan investment performance, salary escalation, retirement ages of employees, expected health care costs, employee turnover, discount rates, and return on plan assets. Changes in these estimates or assumptions could result in an increase or decrease to the accrued benefit obligation and the related costs for both pensions and other post-retirement benefits.

INCOME TAXES

The Company follows the liability method of accounting for income taxes whereby future income taxes are recognized based on the differences between the carrying amounts of assets and liabilities reported in the financial statements and their respective tax bases. The determination of the income tax provision is an inherently complex process requiring management to interpret continually changing regulations and to make certain judgments. While income tax filings are subject to audits and reassessments, management believes adequate provision has been made for all income tax obligations. However, changes in the interpretations or judgments may result in an increase or decrease in the Company's income tax provision in the future.

CONTINGENCIES

The Company is involved in litigation and claims associated with normal operations. Management is of the opinion that any resulting settlements would not materially affect the financial position of the Company as at December 31, 2003. However, the determination of contingent liabilities relating to the litigation and claims is a complex process that involves judgments as to the outcomes and interpretation of laws and regulations. Changes in the judgments or interpretations may result in an increase or decrease in the Company's contingent liabilities in the future.

ACCOUNTING CHANGES

ACCOUNTING CHANGES IN THE CURRENT YEAR

During 2003 the Company revised its accounting policies, as described below, with respect to the translation of its International segment and the expensing of stock options. For details, refer to Note 2 of the 2003 Consolidated Financial Statements.

Translation of International Segment

Effective January 1, 2003 Petro-Canada commenced operating its International segment on a self-sustaining (financially and operationally independent) basis. As a consequence, the Company prospectively changed its accounting for the foreign currency translation of its International business segment, whereby gains and losses arising from the translation of the International financial statements and associated long-term debt into Canadian dollars are now deferred and included as part of shareholders' equity. Previously, these gains and losses were included in earnings in the period of translation. The effect of this change for the year ended December 31, 2003 was a decrease in net earnings of \$70 million.

Stock Options

During the fourth quarter of 2003, the Company elected to begin prospectively expensing, effective January 1, 2003, the value of stock options pursuant to transitional accounting provisions. As a result, the fair value of stock options granted during 2003 is being charged to earnings over the vesting period with a corresponding increase in contributed surplus. The effect of this change for the year ended December 31, 2003 was a decrease in net earnings of \$9 million. For stock options granted in 2002, the Company elected to continue accounting for these options based on the intrinsic value at the grant date and to disclose the pro forma results as if the fair value method has been used. Pro forma information is provided in Note 18 to the 2003 Consolidated Financial Statements.

FUTURE ACCOUNTING CHANGES

As a result of recent accounting pronouncements issued by the Canadian Institute of Chartered Accountants the following changes, to be implemented effective January 1, 2004, will affect the Company's reported results.

Asset Retirement Obligations

Beginning in 2004, asset retirement obligations will be recorded pursuant to new accounting rules. Currently, asset retirement obligations are accrued on an undiscounted unit of production or straight-line basis over the life of the asset. The new accounting standard requires companies to record the fair value of legal obligations associated with the retirement of tangible long-lived assets. The obligations are recorded as liabilities on a discounted basis when incurred and amounts recorded for the related assets are increased by the amount of these liabilities. Over time the liabilities are accreted for the change in their present value and the initial capitalized costs are depreciated over the useful lives of the related assets. The new rules are to be applied retroactively and the impact on the 2004 opening balance sheet is an increase in property, plant and equipment of \$184 million, an increase in deferred credits and other liabilities of \$391 million, a decrease in future income taxes of \$74 million, and a decrease in retained earnings of \$133 million. Had the new standard been in effect for 2003, the effect would have been a decrease in net earnings of \$9 million.

Classification of Expenses

Beginning in 2004 the Company will begin accounting for certain transportation costs, certain third-party gas purchases and diluent purchases as expenses in the consolidated statement of earnings. Currently, these costs and purchases are netted against revenue. The change in accounting represents a reclassification of revenue and expenses and will have no effect on net earnings.

RELATED PARTY TRANSACTIONS

As disclosed in Note 21 to the 2003 Consolidated Financial Statements, transactions with the Government of Canada (which holds approximately 19% of the Company's issued shares at December 31, 2003), its agencies and other related parties, are in the normal course of business and are therefore on the same terms as those accorded other non-related parties.

SHARE DATA

The authorized share capital of Petro-Canada consists of an unlimited number of Common Shares and an unlimited number of preferred shares issuable in series designated as either Senior Preferred Shares or Junior Preferred Shares. As at February 29, 2004 there were 269 934 188 common shares outstanding and no preferred shares outstanding. For details of the Company's share capital and stock options outstanding refer to Note 18 of the 2003 Consolidated Financial Statements.

CORPORATE RESPONSIBILITY

Petro-Canada is deeply committed to responsible business practices. This commitment extends to corporate governance practices, environment, health and safety performance and involvement with the communities where employees live and work. Management, internal reporting and external disclosure systems have evolved to ensure that corporate responsibility is part of day-to-day decision-making. To review Petro-Canada's performance in these areas in more detail, a Report to the Community is published annually to enable the public to assess performance and ongoing efforts in the environmental, social and economic aspects of sustainable development.

CORPORATE GOVERNANCE

Petro-Canada strives to maintain the highest standards of corporate governance, with a focus on a strong and diligent Board of Directors and transparency for shareholders. The Corporation has solid governance and disclosure practices, a commitment to continuously improve those practices, and an ethical corporate culture. Our Code of Business Conduct is required reading for all employees, who must acknowledge their awareness and understanding of the Code every two years.

The Board of Directors is responsible for the oversight of the management of the Corporation's business and affairs. The Board has the statutory authority and obligation to protect and enhance the Corporation's assets and the interest of all shareholders. Members of the Board of Directors, along with management and employees, believe that good corporate governance contributes to the creation of shareholder value.

Petro-Canada's corporate governance practices are aligned with the Toronto Stock Exchange guidelines, and Petro-Canada already satisfies the proposals of several provincial securities regulators published in Multilateral Instrument 58-101, even though they are not yet in effect. As a foreign issuer on the NYSE, Petro-Canada is also subject to the many new rules, regulations and guidelines established by the SEC, NYSE and Sarbanes-Oxley legislation. Petro-Canada is in compliance, and in some cases goes beyond these new corporate governance requirements.

More information about Petro-Canada's corporate governance procedures – including Director independence, compensation, Board committee mandates and the integrity of communication with stakeholders – can be viewed on our Web site at www.petro-canada.ca.

ENVIRONMENT, HEALTH AND SAFETY

Petro-Canada executives are accountable for the effective execution of our Company's Total Loss Management policy and standards which set our environment, health and safety expectations. Petro-Canada conducts a major audit of each business unit or area every four years to assess the implementation of the policy and standards. Our Executive Leadership Team reviews environment, health and safety performance monthly. As well, the Environment, Health and Safety Committee of the Board of Directors reviews critical issues and EHS performance throughout the year.

In 2003, we invested \$414 million in environmental programs, including \$96 million for operating expenses and \$318 million in capital expenditures. Some of the expenditures include site remediation, environmental assessments, and pollution prevention and control equipment. We expect environmental costs to remain high as we prepare to meet federal limits for sulphur in gasoline and distillate, future fuel reformulation requirements, and tighter environmental standards for oil and gas production.

Climate change is one of the most complex issues facing Canadian industry, the Canadian public, and governments today. At Petro-Canada, we support a balanced and responsible approach that promotes action on the issue of climate change. This approach includes the application of best practices and development of technology to reduce greenhouse gas emissions while protecting competitiveness, jobs and prosperity.

Petro-Canada has renewed its commitment to improve energy efficiency in the Upstream and Downstream sectors by an average of one per cent per year from 2000 to 2005. Key components of these improvements include reductions in fuel consumption and the corresponding lowering of greenhouse gas emissions and operating costs.

Petro-Canada is committed to maintaining the highest standards of corporate governance.

Greenhouse Gas Emissions versus Production¹

In 2002, our total Canadian GHG emissions rose 9 per cent above 1990 levels, mainly due to the start-up of Terra Nova. Petro-Canada remains committed to improving energy efficiency to mitigate the impact of growing production levels on GHG emissions.



■ Total Canadian Upstream and Downstream production (million cubic metres of oil equivalent/year)
■ GHG emissions (kilotonnes/year)

¹ 2003 data is not yet available; data is based on reporting 100 per cent from Petro-Canada operated properties.

In 2002, Petro-Canada's total Canadian greenhouse gas emissions increased 34 per cent from the previous year's level, from 5 643 to 7 546 kilotonnes per year. This increase in greenhouse gas emissions corresponds to the large increase in production generated mainly by our Terra Nova facility located off the East Coast of Canada. The total Canadian greenhouse gas emissions in 2002 were nine per cent above 1990 levels, despite the fact that combined Upstream and Downstream production grew by 51 per cent over the same period.

Since 1990, Petro-Canada has improved energy efficiency in the Downstream by 21 per cent and in the Canadian Upstream by 24 per cent. By implementing energy efficiency and emissions reduction projects, our voluntary initiatives have eliminated almost 1.3 million tonnes of annual greenhouse gas emissions since 1990.

Data for 2003 will be provided in this year's Report to the Community.

The safety and well-being of our employees and those working on our behalf is an absolute business priority for Petro-Canada. Our overall Employee Recordable Injury Frequency (per 200 000 person hours) decreased to 0.69 in 2003 from 0.94 in 2002. Recordable injuries decreased to 33 in 2003 from 44 in 2002. Our Contractor Recordable Injury Frequency (per 200 000 person hours) decreased to 2.32 in 2003 from 3.22 in 2002. Contractor recordable injuries decreased to 120 in 2003 from 139 in 2002. Petro-Canada believes that all workplace injuries and illnesses are preventable, and that a 'Zero Harm' workplace is possible and our goal. To achieve the goal of Zero Harm, Petro-Canada continues to innovate in the field of health and safety.

COMMUNITY INVOLVEMENT

Petro-Canada's success as an energy company depends on the support we receive from our stakeholders. We are determined to continually earn that support, not just through excellence in meeting our customers' energy needs, but by playing an active and important role in the communities where we live and operate.

In 2003, Petro-Canada invested approximately \$15 million in over 400 Canadian non-profit organizations in four sectors – education, the environment, health and community services, and arts and culture. This included two unique in-kind contributions: we donated a corporate aircraft and avionics shop, valued at \$1.6 million, to the Southern Alberta Institute of Technology; and turned over the Petro-Canada Research Laboratory, valued at \$6.9 million, to the University of Calgary. We contributed \$630 000 to support Canada's Olympic team, including scholarships, the Podium Fund and the Coaching Excellence Awards. Through our Volunteer Energy Program, we provided 430 grants of \$500 each to non-profit organizations supported by employees and retirees who give their time to the community. The total amount of grants, given out since 1992, surpassed the \$1 million mark in 2003.



* Official Mark of the Canadian Olympic Association



Additional information relating to Petro-Canada may be found on the SEDAR Web site at www.sedar.com.

March 4, 2004

MANAGEMENT'S RESPONSIBILITY FOR THE FINANCIAL STATEMENTS

The preparation and presentation of the Company's consolidated financial statements and the overall quality of the Company's financial reporting are the responsibility of management. The financial statements have been prepared in accordance with generally accepted accounting principles and necessarily include estimates that are based on management's best judgements. Information contained elsewhere in the Annual Report is consistent, where applicable, with that contained in the financial statements.

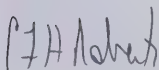
Management is also responsible for installing and maintaining a system of internal controls to provide reasonable assurance that assets are safeguarded and that reliable financial information is produced for preparation of financial statements, and believes that the system of internal controls they have installed has operated effectively in 2003.

Deloitte & Touche LLP, a firm of chartered accountants, were appointed by the shareholders as external auditors of the Company to conduct an independent examination and express their opinion on the consolidated financial statements. The Auditors' Report outlines the auditors' opinion and the scope of their examination. The services provided to the Company by the external auditors are now restricted to the audit of the consolidated financial statements and audit-related services. The Company engaged PricewaterhouseCoopers LLP as contract auditor to provide internal audit services, including a review of the system of internal controls.

The Board of Directors is responsible for overseeing management's performance of its responsibilities for financial reporting and internal control. The Board exercises this responsibility with the assistance of the Audit, Finance and Risk Committee of the Board.



Ronald A. Brenneman
Chief Executive Officer



Ernest F.H. Roberts
Senior Vice-President and Chief Financial Officer

January 28, 2004

AUDIT, FINANCE AND RISK COMMITTEE OF THE BOARD OF DIRECTORS

The Audit, Finance and Risk Committee, which is composed of not fewer than three (currently five) directors who are not employees of the Company, assists the Board of Directors in the discharge of its responsibility for overseeing management's performance of the financial reporting and internal control responsibilities. The Committee reviews the annual and quarterly consolidated financial statements, accounting policies and the overall quality of the Company's financial reporting, and the financial information contained in prospectuses and in reports filed with regulatory authorities, as required. The Committee also reviews and makes recommendations to the Board regarding financial matters and oversees the process that management has in place to identify business risks.

With respect to the external auditors, the Committee reviews and approves the terms of engagement, the scope and plan for the external audit and reviews the results of the audit and the Auditors' Report. The external auditors report to the Committee and to the Board. The Committee discusses the external auditors' independence from management and the Company with the auditors and receives written confirmation of their independence. The Committee also recommends to the Board the external auditors to be appointed by the shareholders and approves in advance fees for the external auditors' services.

With respect to the contract auditor's engagement to provide internal audit services, the Committee reviews the engagement contract, reviews and approves the scope and plan for the internal audit, receives periodic reports and reviews significant findings and recommendations. The contract auditor reports to the Committee and to the Board.

Senior management, the external auditors and the contract auditor attend all Audit, Finance and Risk Committee meetings and each is provided with the opportunity to meet privately with the Committee.



Paul D. Melnuk
Chairman of the Audit, Finance and Risk Committee

January 28, 2004

AUDITORS' REPORTS

To the Shareholders of Petro-Canada:

We have audited the consolidated balance sheet of Petro-Canada as at December 31, 2003 and 2002 and the consolidated statements of earnings, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

The consolidated financial statements of Petro-Canada for the year ended December 31, 2001 were audited by other auditors who have ceased operations. Those auditors expressed an opinion without reservation on those consolidated financial statements in their report dated January 31, 2002. As described in Note 2, these consolidated financial statements have been restated to give effect to the accounting policy change relating to foreign exchange. Also, as described in Note 3, the Company changed the presentation of its segments in 2003, and the amounts in the 2002 and 2001 financial statements relating to segments have been restated to conform to the 2003 segment presentation. We audited the adjustments described in Note 2 and Note 3 that were applied to restate the 2001 consolidated financial statements. In our opinion, such adjustments are appropriate and have been properly applied. However, we were not engaged to audit, review or apply any procedures to the 2001 consolidated financial statements of the Company other than with respect to such adjustments and, accordingly, we do not express an opinion or any other form of assurance on the 2001 financial statements taken as a whole.

Deloitte & Touche LLP

Deloitte & Touche LLP
Chartered Accountants
Calgary, Alberta

January 28, 2004

COMMENTS BY AUDITORS ON CANADA-UNITED STATES OF AMERICA REPORTING DIFFERENCE

In the United States of America, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there are changes in accounting principles that have a material effect on the comparability of the Company's financial statements, such as the changes described in Note 2 to the consolidated financial statements of Petro-Canada. Our report to the shareholders dated January 28, 2004 is expressed in accordance with Canadian reporting standards, which do not require a reference to such changes in accounting principles in the auditors' report when the changes are properly accounted for and adequately disclosed in the financial statements.

Deloitte & Touche LLP

Deloitte & Touche LLP
Chartered Accountants
Calgary, Alberta

January 28, 2004

This report set forth below is a copy of a previously issued audit report by Arthur Andersen LLP. This report has not been reissued by Arthur Andersen LLP in connection with its inclusion in this annual report.

To the Shareholders of Petro-Canada:

We have audited the consolidated balance sheet of Petro-Canada as at December 31, 2001 and 2000 and the consolidated statements of earnings, retained earnings and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2001 and 2000 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2001 in accordance with Canadian generally accepted accounting principles.

Arthur Andersen LLP

Arthur Andersen LLP
Chartered Accountants
Calgary, Alberta

January 31, 2002

Consolidated Statement of Earnings

(stated in millions of Canadian dollars)

For the years ended December 31,	2003	2002	2001
REVENUE			
Operating	\$ 12 209	\$ 9 917	\$ 8 582
Investment and other income (Note 4)	12	—	154
	12 221	9 917	8 736
EXPENSES			
Crude oil and product purchases	5 098	4 556	4 687
Operating, marketing and general (Note 5)	2 407	2 036	1 670
Exploration (Note 14)	271	301	245
Depreciation, depletion and amortization (Notes 5 and 14)	1 539	957	568
Foreign currency translation (Note 6)	(251)	52	102
Interest	182	187	135
	9 246	8 089	7 407
EARNINGS BEFORE INCOME TAXES	2 975	1 828	1 329
PROVISION FOR INCOME TAXES (Note 7)			
Current	1 247	959	528
Future	59	(105)	(45)
	1 306	854	483
NET EARNINGS	\$ 1 669	\$ 974	\$ 846
EARNINGS PER SHARE (dollars) (Note 8)			
Basic	\$ 6.30	\$ 3.71	\$ 3.19
Diluted	\$ 6.23	\$ 3.67	\$ 3.16

Consolidated Statement of Retained Earnings

(stated in millions of Canadian dollars)

For the years ended December 31,	2003	2002	2001
RETAINED EARNINGS AT BEGINNING OF YEAR	\$ 2 380	\$ 1 511	\$ 771
Net earnings	1 669	974	846
Dividends on common shares	(106)	(105)	(106)
RETAINED EARNINGS AT END OF YEAR	\$ 3 943	\$ 2 380	\$ 1 511

Consolidated Statement of Cash Flows

(stated in millions of Canadian dollars)

For the years ended December 31,	2003	2002	2001
OPERATING ACTIVITIES			
Net earnings	\$ 1 669	\$ 974	\$ 846
Items not affecting cash flow (Note 9)	1 432	1 001	597
Exploration expenses (Note 14)	271	301	245
Cash flow	3 372	2 276	1 688
(Increase) decrease in non-cash working capital related to operating activities and other (Note 10)	(164)	(226)	55
Cash flow from operating activities	3 208	2 050	1 743
INVESTING ACTIVITIES			
Expenditures on property, plant and equipment and exploration (Note 14)	(2 315)	(1 861)	(1 681)
Proceeds from sales of assets	165	26	127
Increase in deferred charges and other assets, net	(147)	(72)	(10)
Decrease (increase) in non-cash working capital related to investing activities (Note 10)	94	(16)	96
Acquisition of oil and gas operations of Veba Oil & Gas GmbH (Note 11)	—	(2 234)	—
	(2 203)	(4 157)	(1 468)
FINANCING ACTIVITIES			
Proceeds from issue of long-term debt	804	2 100	—
Reduction of long-term debt	(1 352)	(465)	(475)
Proceeds from issue of common shares	50	30	34
Dividends on common shares	(106)	(105)	(106)
Purchase of common shares (Note 18)	—	—	(362)
	(604)	1 560	(909)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	401	(547)	(634)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	234	781	1 415
CASH AND CASH EQUIVALENTS AT END OF YEAR (Note 12)	\$ 635	\$ 234	\$ 781

Consolidated Balance Sheet

(stated in millions of Canadian dollars)

As at December 31,

2003

2002

ASSETS

CURRENT ASSETS

Cash and cash equivalents (Note 12)	\$ 635	\$ 234
Accounts receivable	1 503	1 596
Inventories (Note 13)	551	585
Prepaid expenses	16	19
	2 705	2 434

PROPERTY, PLANT AND EQUIPMENT, NET (Note 14)

10 759 10 084

GOODWILL (Note 11)

810 709

DEFERRED CHARGES AND OTHER ASSETS (Note 15)

316 212

\$ 14 590 \$ 13 439

LIABILITIES AND SHAREHOLDERS' EQUITY

CURRENT LIABILITIES

Accounts payable and accrued liabilities	\$ 1 822	\$ 1 901
Income taxes payable	300	263
Current portion of long-term debt (Note 16)	6	356
	2 128	2 520

LONG-TERM DEBT (Note 16)

2 223 2 701

DEFERRED CREDITS AND OTHER LIABILITIES (Note 17)

688 621

FUTURE INCOME TAXES (Note 7)

1 830 1 821

COMMITMENTS AND CONTINGENT LIABILITIES (Note 22)

SHAREHOLDERS' EQUITY (Note 18)

7 721 5 776

\$ 14 590 \$ 13 439

Approved on behalf of the Board



R. A. Brenneman
Director



B. F. MacNeill
Director

Notes to Consolidated Financial Statements

(tabular amounts stated in millions of Canadian dollars)

Note 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of Presentation The consolidated financial statements include the accounts of Petro-Canada and of all subsidiary companies (“the Company”) and are prepared in accordance with Canadian generally accepted accounting principles (“GAAP”). Differences between Canadian and United States GAAP are explained in the Notes to the Consolidated Financial Statements.

Substantially all of the Company’s exploration and development activities are conducted jointly with others. Only the Company’s proportionate interest in such activities is reflected in the Consolidated Financial Statements.

The preparation of Consolidated Financial Statements requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingencies. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

(b) Revenue Recognition Revenue from the sale of crude oil, natural gas, natural gas liquids, purchased products, and refined petroleum products is recorded when title passes to the customer.

International operations conducted pursuant to exploration and production sharing agreements (“EPSA’s”) are reflected in the Consolidated Financial Statements based on the Company’s working interest in such operations. Under the EPSA’s, the Company and other non-governmental partners pay all operating and capital costs for exploring and developing the concessions. Each EPSA establishes specific terms for the Company to recover these costs (“Cost Recovery Oil”) in accordance with a formula that is generally limited to a specified percentage of production during each fiscal year and to share in the production profits (“Profit Oil”). Profit Oil is that portion of production remaining after deducting Cost Recovery Oil and is shared between the joint venture partners and the government of each country, varying with the level of production. Profit Oil that is attributable to the government includes an amount in respect of all deemed income taxes payable by the Company under the laws of the respective country. All other government stakes, other than income taxes, are considered to be royalty interests.

(c) Foreign Currency Translation Monetary assets and liabilities are translated into Canadian dollars at rates of exchange in effect at the balance sheet date. With the exception of items pertaining to self-sustaining operations, the other assets and related depreciation, depletion and amortization, other liabilities, revenue and other expense items are translated into Canadian dollars at rates of exchange in effect at the respective transaction dates. The resulting exchange gains or losses are included in earnings.

The Company’s International operations are operated on a self-sustaining basis. Assets and liabilities of the International business segment, including associated long-term debt, are translated into Canadian dollars at period end exchange rates, while revenues and expenses are converted using average rates for the period. Gains and losses from the translation into Canadian dollars are deferred and included in the foreign currency translation adjustment as part of shareholders’ equity.

(d) Income Taxes The Company follows the liability method of accounting for income taxes. Under this method, future income taxes are recognized, using substantively enacted income tax rates, based on the differences between the carrying amounts of assets and liabilities reported in the financial statements and their respective tax bases. The effect of a change in income tax rates on future income tax assets and liabilities is recognized in income in the period the change occurs.

(e) Earnings Per Share Basic earnings per share is calculated by dividing the net earnings available to common shareholders by the weighted average number of common shares outstanding. Diluted earnings per share reflects the potential dilution that would occur if stock options were exercised. The treasury stock method is used in calculating diluted earnings per share, which assumes that any proceeds received from the exercise of in-the-money stock options would be used to purchase common shares at the average market price for the period.

(f) Cash and Cash Equivalents Cash and cash equivalents comprise cash in banks, less outstanding cheques, and short-term investments with a maturity of less than ninety days when purchased.

Note 1 **SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES** *continued*

(g) Inventories Inventories are stated at the lower of cost and net realizable value. Cost of crude oil and product purchases is determined primarily on a “last-in, first-out” (“LIFO”) basis.

(h) Investments Investments in companies over which the Company has significant influence are accounted for using the equity method. Other long-term investments are accounted for using the cost method.

(i) Property, Plant and Equipment Investments in exploration and development activities are accounted for using the successful efforts method. Under this method the acquisition cost of unproved acreage is capitalized. Costs of exploratory wells are initially capitalized pending determination of proved reserves and costs of wells which are assigned proved reserves remain capitalized while costs of unsuccessful wells are charged to earnings. All other exploration costs, including geological and geophysical costs, are charged to earnings as incurred. Development costs, including the cost of all wells, are capitalized.

The interest cost of debt attributable to the construction of major new facilities is capitalized during the construction period.

Producing properties and significant unproved properties are assessed annually, or as economic events dictate, for potential impairment. Impairment is assessed by comparing the estimated net undiscounted future cash flows to the carrying value of the asset.

(j) Depreciation, Depletion and Amortization Depreciation and depletion of capitalized costs of oil and gas producing properties are calculated using the unit of production method.

Depreciation of other plant and equipment is provided on either the unit of production method or the straight line method, based on the estimated service lives of the related assets, as appropriate.

Costs associated with significant development projects are not depleted until commencement of commercial production.

(k) Future Removal and Site Restoration Costs Estimated future removal and site restoration costs which are probable and can be reasonably determined are provided for on either the unit of production method or the straight line method, based on the estimated service lives of the related assets, as appropriate. Future removal and site restoration costs for inactive Downstream sites, net of expected recoveries, are provided for at the time a decision is made to decommission the site. The annual provision is included in operating, marketing and general expenses and is estimated based on current costs and technology and in accordance with existing legislation and industry practice.

(l) Goodwill Goodwill is the excess purchase price over the fair value of identifiable assets and liabilities acquired. Goodwill impairment is assessed annually at year end, or as economic events dictate, by comparing the fair value of the reporting unit to its carrying value, including goodwill. If the fair value of the reporting unit is less than its carrying value, a goodwill impairment loss is recognized as the excess of the carrying value of the goodwill over the fair value of the goodwill.

(m) Stock Option Plan The Company maintains a stock option plan for officers and certain employees as described in the Notes to the Consolidated Financial Statements. Prior to 2003, stock options were accounted for based on the intrinsic value of the award at grant date and as such, no compensation expense was charged to earnings. Effective January 1, 2003 the Company began prospectively accounting for stock options based on the fair value method at the grant date. The compensation expense associated with options granted in 2003 is charged to earnings over the vesting period with a corresponding increase in contributed surplus. On the exercise of stock options, consideration paid and the associated contributed surplus is credited to common shares.

(n) Employee Future Benefits The Company records its obligations under employee benefit plans, net of plan assets where applicable. The costs of pensions and other post-retirement benefits are actuarially determined using the projected benefit method prorated based on service and using management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs. For the purpose of calculating the expected return on plan assets, those assets are measured at fair value. The accrued benefit obligation is discounted using a market rate of interest at the beginning of the year on high quality corporate debt instruments.

(o) Hedging and Derivative Financial Instruments The Company may use derivative financial instruments to manage its exposure to market risks resulting from fluctuations in foreign exchange rates, interest rates and commodity prices. These derivative financial instruments are not used for trading or speculative purposes.

The Company formally documents all derivative instruments designated as hedges, the risk management objective, and the strategy for undertaking the hedge.

Gains and losses on derivative instruments that are designated as and determined to be effective hedges are deferred and recognized in the period of settlement as a component of the related transaction. The Company assesses, both at inception and over the term of the

hedging relationship, whether the derivative instruments used in the hedging transactions are highly effective in offsetting changes in the fair value or cash flows of hedged items. If a derivative instrument ceases to be effective or is terminated, hedge accounting is discontinued. The accumulated gains and losses continue to be deferred and recognized in the Consolidated Statement of Earnings in the period of settlement of the related transaction. Future gains or losses are recognized in the Consolidated Statement of Earnings in the period they occur.

Derivative instruments that are not hedges for accounting purposes are recorded at fair value with any resulting gain or loss recognized in the Consolidated Statement of Earnings in the current period.

Note 2 **CHANGES IN ACCOUNTING POLICIES**

Effective January 1, 2003 Petro-Canada commenced operating its International segment on a self-sustaining basis. As a consequence, the Company prospectively changed its accounting for the foreign currency translation of its International business segment, and gains and losses arising from the translation of the financial statements and associated long-term debt into Canadian dollars are deferred and included as part of shareholders' equity. The effect of this change for the year ended December 31, 2003 was a decrease in net earnings of \$70 million. The change also resulted in an increase in property, plant and equipment of \$152 million, goodwill of \$101 million and shareholders' equity of \$253 million as at December 31, 2003.

During the fourth quarter of 2003, the Company elected to begin prospectively expensing, effective January 1, 2003, the value of stock options pursuant to the transitional accounting provisions of the Canadian Institute of Chartered Accountants for stock-based compensation and other stock-based payments. As a result, stock options granted during 2003 have been accounted for based on the fair value method at the grant date. The fair value associated with these options is charged to earnings over the vesting period with a corresponding increase in contributed surplus. The effect of this change for the year ended December 31, 2003 was a decrease in net earnings of \$9 million. For stock options granted in 2002, the

Company elected to continue accounting for these options based on the intrinsic value at the grant date and to disclose the pro forma results as if the fair value method has been used. Accordingly, the net earnings for 2002 and subsequent years of the vesting period remain unchanged with respect to options issued in 2002 and the pro forma results are disclosed in Note 18 to the Consolidated Financial Statements.

Effective January 1, 2002 the Company adopted, retroactively, the recommendations of the Canadian Institute of Chartered Accountants on accounting for foreign currency translation whereby exchange gains or losses on the translation of long-term debt, excluding the long-term debt associated with the Company's self-sustaining International business segment, are included in net earnings in the current period. Previously, gains or losses on the translation of long-term debt were deferred and amortized over the remaining term of the debt. The effect of this change for the year ended December 31, 2002 was an increase (decrease) in net earnings of \$19 million (2001 – \$(58) million) from the net earnings that would have been reported under the former accounting policy. The change also resulted in a decrease in deferred charges and other assets of \$187 million, a decrease in future income taxes of \$3 million and a decrease in shareholders' equity of \$184 million as of December 31, 2001.

Note 3 **SEGMENTED INFORMATION**

Prior to 2003, the Company reported its operating activities through two Upstream segments and a Downstream segment. Effective January 1, 2003 the reported segments were changed and now comprise four Upstream segments and a Downstream segment. Prior years' segmented information has been restated to conform with the current year presentation.

Upstream operations include the exploration, development, production, transportation and marketing activities

for crude oil, natural gas and natural gas liquids and oil sands. The North American Gas segment includes activity in Western Canada, the Mackenzie Delta, offshore Nova Scotia and Alaska. The East Coast Oil segment comprises activity offshore Newfoundland and includes interests in the Hibernia and Terra Nova oil field operations as well as an interest in the White Rose oil field currently under development. The Oil Sands segment includes an interest in the Syncrude oil sands mining operation as well as the

	UPSTREAM								
	NORTH AMERICAN GAS			EAST COAST OIL			OIL SANDS		
	2003	2002	2001	2003	2002	2001	2003	2002	2001
Revenue									
Sales to customers and other revenues	\$ 1 271	\$ 787	\$ 1 199	\$ 795	\$ 567	\$ 286	\$ 64	\$ -	\$ 5
Inter-segment sales	190	183	184	482	379	102	391	406	356
Segment Revenue	1 461	970	1 383	1 277	946	388	455	406	361
Expenses									
Crude oil and product purchases	-	-	-	-	-	-	-	-	-
Inter-segment transactions	7	3	6	-	-	-	36	-	-
Operating, marketing and general	199	179	195	112	92	41	316	238	222
Exploration	146	206	144	47	17	21	23	23	29
Depreciation, depletion and amortization	263	257	231	261	220	104	178	30	32
Foreign currency translation	-	-	-	-	-	-	-	-	-
Interest	-	-	-	-	-	-	-	-	-
	615	645	576	420	329	166	553	291	283
Earnings before income taxes	846	325	807	857	617	222	(98)	115	78
Provision for income taxes									
Current	227	268	483	313	172	13	(20)	(26)	6
Future	107	(122)	(168)	(49)	15	41	(28)	62	13
	334	146	315	264	187	54	(48)	36	19
Net Earnings	\$ 512	\$ 179	\$ 492	\$ 593	\$ 430	\$ 168	\$ (50)	\$ 79	\$ 59
Capital and Exploration Expenditures									
Property, plant and equipment and exploration expenditures	\$ 560	\$ 530	\$ 548	\$ 344	\$ 289	\$ 279	\$ 448	\$ 462	\$ 304
Deferred charges and other assets	4	(3)	-	4	-	-	-	-	-
Acquisition of oil and gas operations of Veba Oil & Gas GmbH, including goodwill	-	-	-	-	-	-	-	-	-
	\$ 564	\$ 527	\$ 548	\$ 348	\$ 289	\$ 279	\$ 448	\$ 462	\$ 304
Cash Flow (before changes in non-cash working capital)	\$ 985	\$ 534	\$ 651	\$ 869	\$ 687	\$ 338	\$ 127	\$ 196	\$ 136
Total Assets	\$ 2 301	\$ 2 240	\$ 2 129	\$ 2 247	\$ 2 209	\$ 2 090	\$ 1 746	\$ 1 473	\$ 899

MacKay River *in situ* oil sands operation. The International segment includes activity, primarily in the United Kingdom, the Netherlands, Trinidad, Venezuela, Syria, Libya, Kazakhstan, Algeria and Tunisia.

The Downstream segment includes the purchase and sale of crude oil, the refining of crude oil products and the distribution and marketing of these and other purchased products.

All activities, other than those relating to the International segment and Alaska, are conducted within Canada.

Financial information by business segment is presented in the following table as though each segment were a separate business entity. Inter-segment transfers of products, which are accounted for at market value, are eliminated on consolidation. Shared Services includes investment income, interest expense, foreign currency translation and general corporate revenue and expense. Shared Services assets are principally cash and cash equivalents and other general corporate assets.

INTERNATIONAL			DOWNSTREAM			SHARED SERVICES			CONSOLIDATED		
2003	2002	2001	2003	2002	2001	2003	2002	2001	2003	2002	2001
\$ 1 945	\$ 1 239	\$ 20	\$ 8 145	\$ 7 318	\$ 7 158	\$ 1	\$ 6	\$ 68	\$ 12 221	\$ 9 917	\$ 8 736
-	-	-	7	3	6	-	-	-	-	-	-
1 945	1 239	20	8 152	7 321	7 164	1	6	68	12 221	9 917	8 736
-	-	-	5 099	4 556	4 687	(1)	-	-	5 098	4 556	4 687
-	-	-	1 027	968	642	-	-	-	-	-	-
407	288	8	1 299	1 179	1 165	74	60	39	2 407	2 036	1 670
55	55	51	-	-	-	-	-	-	271	301	245
444	249	7	392	200	193	1	1	1	1 539	957	568
-	-	-	-	-	-	(251)	52	102	(251)	52	102
-	-	-	-	-	-	182	187	135	182	187	135
906	592	66	7 817	6 903	6 687	5	300	277	9 246	8 089	7 407
1 039	647	(46)	335	418	477	(4)	(294)	(209)	2 975	1 828	1 329
644	413	(15)	204	242	90	(121)	(110)	(49)	1 247	959	528
88	9	(4)	(118)	(81)	86	59	12	(13)	59	(105)	(45)
732	422	(19)	86	161	176	(62)	(98)	(62)	1 306	854	483
\$ 307	\$ 225	\$ (27)	\$ 249	\$ 257	\$ 301	\$ 58	\$ (196)	\$ (147)	\$ 1 669	\$ 974	\$ 846
\$ 525	\$ 221	\$ 153	\$ 424	\$ 344	\$ 383	\$ 14	\$ 15	\$ 14	\$ 2 315	\$ 1 861	\$ 1 681
-	-	(6)	53	27	16	86	48	-	147	72	10
-	2 234	-	-	-	-	-	-	-	-	2 234	-
\$ 525	\$ 2 455	\$ 147	\$ 477	\$ 371	\$ 399	\$ 100	\$ 63	\$ 14	\$ 2 462	\$ 4 167	\$ 1 691
\$ 890	\$ 583	\$ 27	\$ 601	\$ 380	\$ 589	\$ (100)	\$ (104)	\$ (53)	\$ 3 372	\$ 2 276	\$ 1 688
\$ 3 883	\$ 3 544	\$ 186	\$ 3 838	\$ 3 841	\$ 3 556	\$ 575	\$ 132	\$ 774	\$ 14 590	\$ 13 439	\$ 9 634

Note 4 GAINS (LOSSES) ON DISPOSAL OF ASSETS

Investment and other income includes net gains (losses) on disposal of \$42 million (2002 – \$(2) million; 2001 – \$49 million).

Note 5 ASSET WRITEDOWNS

Following a review of its Eastern Canada refining and supply operations, Petro-Canada announced in September, 2003 it will be ceasing its Oakville refining operations and expanding the existing terminalling facilities. The total charge to earnings related to the shutdown, which is expected to occur December 31, 2004, will be approximately \$200 million after-tax including approximately \$160 million for asset write-downs and increased depreciation, \$20 million for de-commissioning costs and \$20 million for employee related costs. For the year ended December 31, 2003 \$250 million has been recorded to the following expenses in the Downstream segment:

	Pre-Tax	After Tax
Operating, marketing and general expense (de-commissioning and employee related costs)	\$ 54	\$ 32
Depreciation and amortization expense (asset write-downs and increased depreciation)	196	119
	\$ 250	\$ 151

Depreciation, depletion and amortization expense for the year ended December 31, 2003 also includes charges of \$46 million (\$46 million after-tax) relating to the impairment of assets in Kazakhstan and \$136 million (\$82 million after-tax) relating mainly to engineering costs incurred in finalizing the Company's strategy for converting the Edmonton refinery to process an oil sands feedstock. The charges were recorded in the International and Oil Sands segments respectively.

Note 6 FOREIGN CURRENCY TRANSLATION

Foreign currency translation consists of:

	2003	2002	2001
(Gain) loss on translation of foreign currency denominated long-term debt ¹	\$ (251)	\$ (11)	\$ 102
Loss on translation of International business segment (Note 2)	–	63	–
	\$ (251)	\$ 52	\$ 102

¹ Gains or losses on foreign currency denominated long-term debt associated with the self-sustaining International business segment are deferred and included as part of shareholders' equity.

Note 7 INCOME TAXES

The computation of the provision for income taxes, which requires adjustment to earnings before income taxes for non-taxable and non-deductible items, is as follows:

	2003	2002	2001
Earnings before income taxes	\$ 2 975	\$ 1 828	\$ 1 329
Add (deduct):			
Non-deductible royalties and other payments to provincial governments, net	392	277	413
Resource allowance	(542)	(467)	(476)
Equity in earnings of affiliates	(11)	(9)	(9)
Non-taxable foreign exchange	(237)	52	87
Other	28	(3)	(1)
Earnings as adjusted before income taxes	\$ 2 605	\$ 1 678	\$ 1 343
Canadian Federal income tax rate	38.0%	38.0%	38.0%
Income tax on earnings as adjusted at Canadian			
Federal income tax rate	\$ 990	\$ 638	\$ 510
Large Corporations Tax	16	16	15
Provincial and other income taxes, net of federal abatement	17	27	49
Future income taxes (decrease) increase due to federal and provincial rate changes	(45)	4	(61)
Higher foreign income tax rates	337	176	-
Income tax credits and other	(9)	(7)	(30)
Provision for income taxes	\$ 1 306	\$ 854	\$ 483
Effective income tax rate on earnings before income taxes	43.9%	46.7%	36.3%

Future income taxes consists of the following future income tax liabilities (assets) relating to temporary differences for:

	2003	2002
Property, plant and equipment	\$ 1 975	\$ 1 992
Partnership income ¹	381	278
Inventories	(134)	(161)
Deferred credits and other liabilities	(224)	(191)
Deferred charges and other assets	43	18
Loss carryforwards and other	(211)	(115)
	\$ 1 830	\$ 1 821

¹ Taxable income for certain Canadian Upstream activities are generated by a partnership and the related taxes will be included in current income taxes in the next year.

Deferred distribution taxes associated with International business operations have not been recorded. Based on current plans, repatriation of funds in excess of foreign reinvestment will not result in material additional tax expense.

Complex income tax issues which involve interpretations of continually changing regulations are encountered in computing the provision for income taxes. Management believes that adequate provision has been made for all such outstanding issues.

Note 8 EARNINGS PER SHARE

The weighted average number of common shares outstanding used in the calculation of basic earnings per share and diluted earnings per share, assuming that all dilutive outstanding stock options were exercised, was:

	2003	2002	2001
Average shares outstanding (millions)			
Basic	264.9	262.8	264.9
Diluted	267.9	265.7	267.4

For the year ended December 31, 2003 no stock options (2002 – 375 700 stock options with an exercise price of \$45.68; 2001 – nil) were excluded in the diluted earnings per share calculation. Stock options are excluded when the exercise price exceeds the average share price in a respective period.

Note 9 ITEMS NOT AFFECTING CASH FLOW

	2003	2002	2001
Depreciation, depletion and amortization	\$ 1 539	\$ 957	\$ 568
Future income taxes	59	(105)	(45)
Provision for future removal and site restoration costs	70	27	17
(Gain) loss on translation of foreign currency denominated long-term debt	(251)	(11)	102
(Gain) loss on disposal of assets	(42)	2	(49)
Amortization of debt issue costs	22	14	1
Other	35	27	3
Foreign currency losses	–	90	–
	\$ 1 432	\$ 1 001	\$ 597

Note 10 (INCREASE) DECREASE IN NON-CASH WORKING CAPITAL AND OTHER

	2003	2002	2001
Operating activities and other			
Accounts receivable	\$ 93	\$ (268)	\$ 465
Inventories	34	(74)	–
Prepaid expenses	3	9	5
Accounts payable and accrued liabilities	(219)	467	(433)
Income taxes payable	37	(313)	40
Current portion of long-term liabilities and other	(112)	(47)	(22)
	\$ (164)	\$ (226)	\$ 55
Investing activities			
Accounts receivable	\$ –	\$ –	\$ 64
Accounts payable and accrued liabilities	94	(16)	32
	\$ 94	\$ (16)	\$ 96
Financing activities			
Accounts receivable	\$ –	\$ –	\$ 2
Accounts payable and accrued liabilities	–	–	(2)
	\$ –	\$ –	\$ –

Non-cash working capital is comprised of current assets and current liabilities other than cash and cash equivalents and current portion of long-term debt.

Note 11 ACQUISITION OF OIL AND GAS OPERATIONS OF VEBA OIL & GAS GMBH

On May 2, 2002 the Company acquired the shares of companies holding the majority of the international oil and gas operations of Veba Oil & Gas GmbH and on December 10, 2002 the Company acquired certain of the remaining operations which were subject to rights of first refusal. The total acquisition cost, consisting of cash

consideration and acquisition costs, was \$2 234 million and the results of these operations have been included in the consolidated financial statements from the dates of acquisition.

The acquisition was accounted for by the purchase method of accounting and the allocation of fair value to the assets acquired and liabilities assumed was:

Property, plant and equipment	\$ 2 012
Goodwill	709
Current assets, excluding cash of \$15 million	640
Deferred charges and other assets	6
Total assets acquired	3 367
Current liabilities	634
Future income taxes	387
Deferred credits and other liabilities	112
Total liabilities assumed	1 133
Net assets acquired	\$ 2 234

Goodwill, which is not tax deductible, was assigned to the Company's International business segment.

Funds for the acquisition were provided from credit facilities arranged with certain banks (Note 16) and from cash and cash equivalents.

Note 12 CASH AND CASH EQUIVALENTS

Short-term investments are considered to be cash equivalents and are recorded at cost, which approximates market value.

	2003	2002
Cash	\$ 60	\$ 139
Less: outstanding cheques	39	167
	21	(28)
Short-term investments	614	262
	\$ 635	\$ 234

Cash payments for interest and income taxes were as follows:

	2003	2002	2001
Interest	\$ 156	\$ 178	\$ 158
Income taxes	\$ 1 232	\$ 1 172	\$ 483

Note 13 **INVENTORIES**

	2003	2002
Crude oil, refined products and merchandise	\$ 394	\$ 429
Materials and supplies	157	156
	\$ 551	\$ 585

Note 14 **PROPERTY, PLANT AND EQUIPMENT**

	2003			2002			2003	2002
	Cost	Accumulated Depreciation, Depletion and Amortization	Net	Cost	Accumulated Depreciation, Depletion and Amortization	Net	Expenditures on Property, Plant and Equipment ¹	
Upstream								
Canada								
North American Gas	\$ 4 158	\$ 2 082	\$ 2 076	\$ 3 905	\$ 1 914	\$ 1 991	\$ 414	\$ 324
East Coast Oil	2 934	820	2 114	2 637	562	2 075	297	272
Oil Sands	2 189	563	1 626	1 905	523	1 382	425	439
International	2 898	549	2 349	2 373	296	2 077	470	166
	12 179	4 014	8 165	10 820	3 295	7 525	1 606	1 201
Downstream								
Refining	3 167	1 690	1 477	2 867	1 423	1 444	303	222
Marketing and other	2 273	1 192	1 081	2 208	1 133	1 075	121	122
	5 440	2 882	2 558	5 075	2 556	2 519	424	344
Other property, plant and equipment	449	413	36	443	403	40	14	15
	\$ 18 068	\$ 7 309	\$ 10 759	\$ 16 338	\$ 6 254	\$ 10 084	\$ 2 044	\$ 1 560

Interest capitalized during 2003 amounted to \$7 million (2002 – \$4 million; 2001 – \$16 million).

Costs of \$314 million (2002 – \$638 million) relating to the Upstream International operations and \$422 million (2002 – \$250 million) relating to non-producing East Coast Oil projects are not currently being depleted.

Capital leases at a net cost of \$70 million (2002 – \$74 million) and \$29 million (2002 – \$31 million) are included in the assets of East Coast Oil and Oil Sands, respectively (Note 16).

¹ Exploration expenses of \$271 million (2002 – \$301 million; 2001 – \$245 million) charged to earnings are reclassified from operating activities and included with expenditures on property, plant and equipment and exploration under investing activities in the Consolidated Statement of Cash Flows.

Note 15 **DEFERRED CHARGES AND OTHER ASSETS**

	2003	2002
Investments	\$ 72	\$ 77
Deferred pension funding	49	34
Deferred financing costs	97	36
Other long-term assets	98	65
	\$ 316	\$ 212

Note 16 LONG-TERM DEBT

	Maturity	2003	2002
Debentures and notes			
5.35% unsecured senior notes ¹			
(U.S. \$300 million)	2033	\$ 388	\$ —
7.00% unsecured debentures			
(U.S. \$250 million)	2028	323	395
7.875% unsecured debentures			
(U.S. \$275 million)	2026	355	434
9.25% unsecured debentures			
(U.S. \$300 million)	2021	388	474
4.00% unsecured senior notes ¹			
(U.S. \$300 million)	2013	388	—
Capital leases (Note 14) ²	2007-2017	94	115
Acquisition credit facilities ³	2005	293	1 639
		2 229	3 057
Current portion		(6)	(356)
		\$ 2 223	\$ 2 701

Interest on long-term debt was \$177 million in 2003 (2002 – \$182 million; 2001 – \$134 million).

1 In anticipation of issuing these senior notes, the Company entered into interest rate derivatives which resulted in effective interest rates of 6.073% for the 5.35% notes due in 2033 and 4.838% for the 4.00% notes due in 2013.

2 The Company is party to a transportation agreement to transport bitumen from the MacKay River production facilities to the Athabasca Pipeline Terminal. The agreement is for an initial term of fifteen years ending in 2017 and is extendable at the Company's option for an additional ten years.

The Company is party to an agreement for the time charter and operation of a vessel for the transportation of East Coast Canada crude oil production. The agreement is for an initial term of 10 years ending in 2007 and extendable at the Company's option for up to an additional 15 years.

The transportation and time charter agreements are accounted for as capital leases and have implicit rates of interest of 14.65% and 11.90%, respectively. The aggregate remaining repayments under the transportation and time charter agreements are \$94 million, including the following amounts in the next five years: 2004 – \$6 million, 2005 – \$7 million, 2006 – \$8 million, 2007 – \$8 million, 2008 – \$2 million.

3 The Company established two unsecured credit facilities with certain banks for the acquisition of the oil and gas operations of Veba Oil & Gas GmbH (Note 11). The credit facilities totalled \$3 320 million of which \$2 100 million was drawn in the form of floating rate Canadian dollar bankers' acceptances in 2002. During 2003 and 2002 the Company repaid \$1 807 million and cancelled an additional \$770 million of the facilities which reduced the amount of the facilities to \$743 million at December 31, 2003, of which \$293 million is outstanding and repayable in 2005.

Note 17 DEFERRED CREDITS AND OTHER LIABILITIES

	2003	2002
Future removal and site restoration costs	\$ 382	\$ 344
Post-retirement benefits	153	143
Long-term liabilities	153	134
	\$ 688	\$ 621

Note 18 **SHAREHOLDERS' EQUITY**

	2003	2002
Common shares	\$ 1 308	\$ 1 258
Contributed surplus	2 147	2 138
Retained earnings	3 943	2 380
Foreign currency translation adjustment (Note 2)	323	—
	\$ 7 721	\$ 5 776

The authorized share capital is comprised of an unlimited number of:

- (a) Preferred shares issuable in series designated as Senior Preferred Shares
- (b) Preferred shares issuable in series designated as Junior Preferred Shares
- (c) Common shares

Changes in common shares and contributed surplus were as follows:

	2003			2002		
	Shares	Amount	Contributed Surplus	Shares	Amount	Contributed Surplus
Balance at beginning of year	263 594 977	\$ 1 258	\$ 2 138	262 191 041	\$ 1 228	\$ 2 138
Issued for cash under employee stock option and share purchase plans	1 991 116	50	—	1 403 936	30	—
Stock-based compensation	—	—	9	—	—	—
Balance at end of year	265 586 093	\$ 1 308	\$ 2 147	263 594 977	\$ 1 258	\$ 2 138

The Company repurchased common shares under a Normal Course Issuer Bid that commenced on November 1, 2000 and ended on October 31, 2001. During 2001 9 429 755 shares were purchased for a total of \$362 million. The excess of purchase cost over the carrying amount of the shares purchased was recorded as a reduction of contributed surplus.

Stock Option Plan

The Company maintains a stock option plan and may grant options to officers and certain employees for up to 22 million common shares. The stock options have a term of 10 years, vest over periods of up to four years and are exercisable at the market prices for the shares on the dates that the options were granted.

Changes in the number of outstanding stock options were as follows:

	2003		2002	
	Number	Weighted-Average Exercise Price (dollars)	Number	Weighted-Average Exercise Price (dollars)
Balance at beginning of year	8 225 984	\$ 30	7 216 770	\$ 26
Granted	2 481 000	51	2 482 700	36
Exercised	(1 991 116)	25	(1 403 936)	22
Cancelled	(95 275)	41	(69 550)	30
Balance at end of year	8 620 593	\$ 37	8 225 984	\$ 30

The following stock options were outstanding as at December 31, 2003:

Number	Range of Exercise Prices (dollars)	Weighted-Average Life (years)	Options Outstanding		Number	Options Exercisable Weighted-Average Exercise Price (dollars)
			Weighted-Average Exercise Price (dollars)			
541 762	\$ 11 to 18	4.6	\$ 16		541 762	\$ 16
1 067 315	19 to 25	5.5	21		862 030	21
2 400 592	26 to 35	7.5	33		960 217	31
2 199 324	36 to 46	7.3	38		1 004 050	38
2 411 600	47 to 51	9.1	51		—	—
8 620 593	\$ 11 to 51	7.9	\$ 37		3 368 059	\$ 28

The following table presents the pro forma net earnings and the pro forma earnings per share computed assuming the fair value based accounting method had been used to account for the compensation cost of stock options granted in 2002.

	2003 Net Earnings	Earnings per Share		2002 Net Earnings	Earnings per Share	
		Basic (dollars)	Diluted (dollars)		Basic (dollars)	Diluted (dollars)
Net earnings as reported	\$ 1 669	\$ 6.30	\$ 6.23	\$ 974	\$ 3.71	\$ 3.67
Pro forma adjustment	8	0.03	0.03	6	0.03	0.03
Pro forma net earnings	\$ 1 661	\$ 6.27	\$ 6.20	\$ 968	\$ 3.68	\$ 3.64

The estimated fair value of stock options granted in 2003, which is charged to earnings (Notes 1(m) and 2), was \$17.50 per share. The estimated weighted average fair value of stock options granted in 2002, which is incorporated in the pro forma earnings information above, was \$12.74 per share. The fair values have been determined using the Black-Scholes option-pricing model with the following assumptions:

	2003	2002
Risk-free interest rate	4.4%	4.9%
Expected hold period to exercise	6 years	6 years
Volatility in the market price of common shares	32%	33%
Estimated annual dividend	1.4%	1.4%

Note 19 EMPLOYEE FUTURE BENEFITS

The Company maintains pension plans with defined benefit and defined contribution provisions, and provides certain health care and life insurance benefits to its qualifying retirees. The actuarially determined cost of these benefits is accrued over the estimated service life of employees. The defined benefit provisions are generally based upon years of service and average salary during the final years of employment. Certain defined benefit options

require employee contributions and the balance of the funding for the registered plans is provided by the Company, based upon the advice of an independent actuary. The defined contribution option provides for an annual contribution of 5% to 8% of each participating employee's pensionable earnings. Substantially all of the pension assets are invested in equity, fixed income and other marketable securities.

Benefit Plan Expense	Pension Plans			Other Post-Retirement Plans		
	2003	2002	2001	2003	2002	2001
(a) Defined benefit plans						
Employer current service cost	\$ 27	\$ 25	\$ 22	\$ 4	\$ 3	\$ 2
Interest cost	78	74	70	12	11	11
Expected return on plan assets	(65)	(83)	(88)	—	—	—
Amortization of transitional (asset) obligation	(5)	(5)	(5)	2	2	2
Amortization of net actuarial losses	26	7	—	—	—	—
	61	18	(1)	18	16	15
(b) Defined contribution plans	11	10	7			
Total expense	\$ 72	\$ 28	\$ 6	\$ 18	\$ 16	\$ 15
Benefit Plan Funding	\$ 86	\$ 22	\$ 9	\$ 8	\$ 7	\$ 7

Financial Status of Defined Benefit Plans	Pension Plans		Other Post-Retirement Plans	
	2003	2002	2003	2002
Fair value of plan assets	\$ 1 052	\$ 927	\$ —	\$ —
Accrued benefit obligation	1 344	1 206	211	186
Funded status – plan deficit ¹	(292)	(279)	(211)	(186)
Unamortized transitional (asset) obligation	(34)	(39)	19	21
Unamortized net actuarial losses	375	352	39	22
Accrued benefit asset (liability)	\$ 49	\$ 34	\$ (153)	\$ (143)
Reconciliation of Plan Assets				
Fair value of plan assets at beginning of year	\$ 927	\$ 1 039	\$ —	\$ —
Acquisition	—	26	—	—
Contributions	86	22	8	7
Benefits paid	(63)	(61)	(8)	(7)
Actual gain (loss) on plan assets	115	(91)	—	—
Other	(13)	(8)	—	—
Fair value of plan assets at end of year	\$ 1 052	\$ 927	\$ —	\$ —
Reconciliation of Accrued Benefit Obligation				
Accrued benefit obligation at beginning of year	\$ 1 206	\$ 1 119	\$ 186	\$ 172
Acquisition	—	33	—	—
Current service cost	27	25	4	3
Interest cost	78	74	12	11
Benefits paid	(63)	(61)	(8)	(7)
Actuarial losses	99	12	17	7
Other	(3)	4	—	—
Accrued benefit obligation at end of year	\$ 1 344	\$ 1 206	\$ 211	\$ 186

¹ The pension and other post-retirement plans included in the financial status information are not fully funded.

Note 19 EMPLOYEE FUTURE BENEFITS *continued*

Defined Benefit Plan Assumptions	2003	2002	2001
Year-end obligation discount rate	6.0%	6.5%	6.5%
Long-term rate of return on plan assets	7.5%	8.0%	8.0%
Rate of compensation increase, excluding merit increases	3.0%	3.0%	3.0%
Annual increase in the per capita cost of:			
Medical benefits	7.5% ¹	7.5%	7.5%
Dental benefits	3.5%	3.5%	3.5%

¹ 4.5% in 2009 and thereafter.

Note 20 FINANCIAL INSTRUMENTS

The Company is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the course of its normal business operations. The Company monitors its exposure to market fluctuations and may use derivative instruments to manage these risks, as it considers appropriate. These derivative instruments are entered into solely for hedging purposes.

Crude Oil and Products

The Company enters into forward contracts and options to reduce exposure to Downstream margin fluctuations, including margins on fixed price product sales, and short-term price fluctuations on the purchase of foreign and domestic crude oil and refined products.

Natural Gas

The Company enters into forward contracts to purchase natural gas to manage its exposure on fixed price sales of natural gas and to manage its fuel costs on fixed price product sales.

Currency

The Company enters into forward contracts to reduce its exposure to exchange rate movements between the Canadian dollar and the foreign currency related to fixed price product sales. There were no currency derivatives in place as at December 31, 2003.

Interest Rates

In anticipation of issuing U.S. dollar notes in 2003, the Company entered into interest rate derivatives to hedge a portion of its exposure to adverse interest rate fluctuations. The Company also implements short duration Forward Rate Agreements to manage interest rate exposure on floating rate debt. There were no interest rate derivatives in place as at December 31, 2003.

Note 20 **FINANCIAL INSTRUMENTS** *continued*

The Company's outstanding contracts for derivative instruments and the related fair values at December 31, 2003 were as follows:

	Quantity	Average Price ¹	Fair Value	Maturity
Crude Oil and Products (millions of barrels)				
Crude oil purchase	2.2	\$ 35.31	\$ 8	2004/2005
Products purchase	1.2	\$ 31.08	1	2004
Natural Gas (billions of cubic feet)				
Natural gas purchase	0.4	\$ 6.14	–	2004
			\$ 9	

¹ Canadian dollars per barrel or per thousand cubic feet, as applicable.

Derivative instruments involve a degree of credit risk. The Company controls this risk through the establishment of credit policies and limits which are applied in the selection of counterparties. Market risk relating to changes in value or settlement cost of the Company's derivative instruments is essentially offset by gains or losses on the hedged positions.

The fair value, the related method of determination and the carrying value of the Company's financial instruments were as follows:

Current Assets/Current Liabilities

The fair value of financial instruments included in current assets and current liabilities, excluding the current portion of long-term debt, approximates the carrying amount of these instruments due to their short maturity.

Long-Term Debt

The fair value of long-term debt is based on publicly quoted market values.

Derivative Instruments

The fair value of derivative instruments, which is based on quotes provided by brokers, represents an approximation of amounts that would be received or paid to counterparties to settle these instruments prior to maturity. The Company plans to hold all derivative instruments outstanding at December 31, 2003 to maturity.

	2003		2002	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial instruments included in current assets and current liabilities	\$ 316	\$ 316	\$ (71)	\$ (71)
Long-term debt	\$ (2 229)	\$ (2 432)	\$ (3 057)	\$ (3 358)
Derivative instruments	\$ –	\$ 9	\$ –	\$ (5)

Note 21 RELATED PARTY TRANSACTIONS

Transactions with the Government of Canada (which holds 19% of the Company's issued shares at December 31, 2003), its agencies and other related parties, are in the normal

course of business and are therefore on the same terms as those accorded to non-related parties.

Note 22 COMMITMENTS AND CONTINGENT LIABILITIES

(a) The Company has leased property and equipment under various long-term operating leases for periods up to 2013. The minimum annual rentals for non-cancellable operating leases are estimated at \$115 million in 2004, \$90 million in 2005, \$78 million in 2006, \$69 million in 2007, \$60 million in 2008 and \$55 million per year thereafter until 2013.

(b) The Company is involved in litigation and claims associated with normal operations. Management is of the opinion that any resulting settlements would not materially affect the financial position of the Company.

Note 23 GENERALLY ACCEPTED ACCOUNTING PRINCIPLES IN THE UNITED STATES

The Company's Consolidated Financial Statements have been prepared in accordance with Canadian GAAP, which differ in some respects from those applicable in the United States. The following are the significant differences in accounting principles as they pertain to the accompanying Consolidated Financial Statements:

(a) Income Taxes This liability method followed by the Company differs from United States GAAP due to the application of transitional provisions upon adoption, the use of substantive versus enacted tax rates and the accounting for certain Canadian income tax credits and allowances.

(b) Interest Capitalization United States GAAP requires that interest be capitalized as part of the cost of certain assets while they are being prepared for their intended use. The Company capitalizes interest attributable to the construction of major new facilities and does not capitalize interest on all assets that would require interest capitalization under United States GAAP.

(c) Contributed Surplus In prior years the Company transferred amounts from contributed surplus to the accumulated deficit. Under United States GAAP these transfers would not have occurred.

(d) Derivative Instruments and Hedging Under United States GAAP the accounting for derivative instruments and hedging activities is contained in the Statement of Financial Accounting Standards No. 133 ("SFAS 133"). SFAS 133 establishes accounting and reporting standards requiring that all derivative instruments be recorded in the balance sheet as either an asset or a liability measured at fair value and requires that changes in the fair value be recognized currently in earnings unless specific hedge accounting criteria are met. For cash flow hedges, changes in the fair value of the derivative instrument are recognized in net earnings in the same period as the hedged item and any changes in the fair value prior to that period are recognized in other comprehensive income. For fair value hedges, both the derivative instrument and the underlying commitment are recognized on the balance sheet at their fair value and any changes in the fair value are recognized currently in net earnings.

(e) Minimum Pension Liability United States GAAP requires a minimum pension liability be recorded for underfunded pension plans. The change in the minimum liability, representing the excess of unfunded accumulated benefit obligations over previously recorded pension cost liabilities, is recognized in other comprehensive income.

Note 23 **GENERALLY ACCEPTED ACCOUNTING PRINCIPLES IN THE UNITED STATES** *continued*

(f) Comprehensive Income United States GAAP utilizes the concept of comprehensive income, which includes net earnings and other comprehensive income. There is no similar concept under Canadian GAAP. Other comprehensive income represents the change in equity during the period from transactions and other events from non-owner sources and includes such items as changes in the fair value of cash flow hedges, minimum pension liability adjustments and certain foreign currency translation adjustments.

(g) Asset Retirement Obligations Under United States GAAP the accounting for asset retirement obligations is contained in the Statement of Financial Accounting Standards No. 143 ("SFAS 143"). SFAS 143 requires companies to record the fair value of legal obligations associated with the retirement of tangible long-lived assets. These obligations are recorded as liabilities on a discounted basis when incurred and amounts recorded for the related

assets are increased by the amount of these liabilities. Over time the liabilities are accreted for the change in their present value and the initial capitalized costs are depreciated over the useful lives of the related assets. Under current Canadian GAAP and previous United States GAAP, asset retirement obligations are accrued on an undiscounted unit of production or straight line basis over the life of the asset. A liability is not recorded under either United States or Canadian GAAP for assets with an indeterminate useful life.

SFAS 143 was effective January 1, 2003 for United States GAAP purposes and the cumulative effect adjustment from initial application is charged to net earnings under United States GAAP in the current year. Changes to Canadian accounting standards, effective January 1, 2004, are expected to eliminate this GAAP difference in future years.

The application of United States GAAP would have the following effects on earnings as reported:

	2003	2002	2001
Net earnings as reported in the consolidated statement of earnings	\$ 1 669	\$ 974	\$ 846
Adjustments, before income taxes			
Capitalization of interest and related amortization	21	25	53
Accounting for income taxes	(9)	(111)	(51)
Asset retirement obligations	(15)	—	—
Other	—	(3)	(4)
Income taxes on above items	9	10	3
Net earnings, as adjusted before cumulative effect of change in accounting policy	1 675	895	847
Cumulative effect of change in accounting policy, net of income taxes	(114)	—	—
Net earnings, as adjusted	\$ 1 561	\$ 895	\$ 847
Earnings, as adjusted before cumulative effect of change in accounting policy per share			
Basic	\$ 6.32	\$ 3.41	\$ 3.20
Diluted	\$ 6.25	\$ 3.37	\$ 3.17
Earnings, as adjusted per share			
Basic	\$ 5.89	\$ 3.41	\$ 3.20
Diluted	\$ 5.83	\$ 3.37	\$ 3.17
Comprehensive Income			
Net earnings, as adjusted	\$ 1 561	\$ 895	\$ 847
Unrealized gain (loss) on financial derivatives	8	4	(7)
Minimum pension liability	(11)	(111)	—
Foreign currency translation adjustment	323	—	—
	\$ 1 881	\$ 788	\$ 840

The application of United States GAAP would have the following effects on the consolidated balance sheets as reported:

	December 31, 2003		December 31, 2002	
	As Reported	United States GAAP	As Reported	United States GAAP
Current assets	\$ 2 705	\$ 2 705	\$ 2 434	\$ 2 434
Property, plant and equipment, net	10 759	11 521	10 084	10 662
Goodwill	810	789	709	688
Deferred charges and other assets	316	314	212	209
Current liabilities	2 128	2 119	2 520	2 525
Long-term debt	2 223	2 223	2 701	2 701
Deferred credits and other liabilities	688	1 209	621	808
Future income taxes	1 830	2 058	1 821	2 073
Common shares	1 308	1 308	1 258	1 258
Contributed surplus	2 147	3 269	2 138	3 260
Retained earnings	3 943	2 937	2 380	1 482
Foreign currency translation adjustment	323	—	—	—
Accumulated other comprehensive income (loss)	\$ —	\$ 206	\$ —	\$ (114)

Recent Accounting Pronouncements

United States GAAP requires the disclosure of accounting pronouncements that have been issued but are not yet effective for the Company's reporting. The following applicable accounting pronouncement has been recently issued:

Variable Interest Entities

In January, 2003 the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 46 Consolidation of Variable Interest Entities ("FIN 46"). FIN 46 provides criteria for identifying variable interest entities ("VIEs") and further criteria for determining what

entity, if any, should consolidate them. In general, VIEs are entities that either do not have equity investors with voting rights or have equity investors that do not provide sufficient financial resources for the entity to support its activities. In December 2003, the FASB issued FIN 46(R) to clarify some of the provisions of FIN 46 and to exempt certain entities from its requirements. FIN 46 is effective to the Company beginning January 1, 2004. The Company does not expect there to be any material impact on its United States GAAP consolidated financial statements when FIN 46 is adopted.

Petro-Canada Reserves of Crude Oil, Natural Gas Liquids, Natural Gas, Bitumen and Synthetic Crude Oil

(Crude oil and equivalents in millions of barrels; natural gas in billions of cubic feet)

Proved Developed and Undeveloped Reserves Before Royalties^{1,2,3,4,5}

	INTERNATIONAL							
	NORTHWEST EUROPE ¹⁰		NORTH AFRICA & NEAR EAST ^{9,11,12,13}		NORTHERN LATIN AMERICA ^{9,14,15}		SUBTOTAL	
	Crude oil & NGL	Natural Gas	Crude oil & NGL	Natural Gas	Crude oil & NGL	Natural Gas	Crude oil & NGL	Natural Gas
Beginning of year 2002	–	–	11	–	–	–	11	–
Revisions of previous estimates ¹⁶	3	11	45	10	–	–	48	21
Sale of reserves in place	–	–	–	–	–	–	–	–
Purchase of reserves in place	59	149	269	78	–	346	328	573
Discoveries, extensions and improved recovery	10	22	–	–	–	–	10	22
Production	(10)	(22)	(36)	(11)	–	(5)	(46)	(38)
End of year 2002	62	160	289	77	–	341	351	578
Revisions of previous estimates ¹⁶	14	(8)	24	–	–	–	38	(8)
Sale of reserves in place	–	(4)	–	–	–	–	–	(4)
Purchase of reserves in place	3	7	–	–	–	–	3	7
Discoveries, extensions and improved recovery	–	–	–	–	–	6	–	6
Production	(14)	(29)	(52)	(12)	–	(23)	(66)	(64)
End of year 2003	65	126	261	65	–	324	326	515

Proved Undeveloped Reserves Before Royalties^{17,18}

Beginning of year 2002	–	–	10	–	–	–	10	–
End of year 2002	10	22	51	–	–	275	61	297
End of year 2003	–	–	36	–	–	190	36	190

1 In order to harmonize its oil and gas disclosure in both Canada and the U.S., Petro-Canada applied for, and received, certain exemptions to reserves disclosure requirements as set out in National Instrument NI 51-101; *Standards of Disclosure for Oil and Gas Activities*. (NI 51-101). These exemptions permit Petro-Canada to use its own staff of qualified reserves evaluators to prepare the Company's reserves estimates and to use U.S. Securities and Exchange Commission (SEC) and Financial Accounting Standards Board (FASB) standards when preparing and reporting reserves. Such reserves information may differ from reserves information prepared in accordance with Canadian disclosure standards under NI 51-101. These differences relate to the SEC requirement for disclosure only of proved reserves calculated at constant year-end prices and costs while NI 51-101 requires disclosure of proved reserves at constant prices and costs and proved plus probable reserves at forecast prices and costs. Also, the definition of proved reserves differs between SEC and NI 51-101 requirements. However, this difference should not be material. The Canadian Oil and Gas Evaluation Handbook (the source document for reserves definitions under NI 51-101) supports this view.

2 Petro-Canada employs the services of independent third party evaluators/auditors to assess its reserves policies, practices and procedures and its reserves estimates.

3 Proved reserves before royalties are Petro-Canada's working interest reserves before the deduction of Crown or other royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production. No reserve quantities have been included to reflect royalty interests Petro-Canada has in various properties.

4 Proved reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those proved reserves that are expected to be recovered from existing wells or facilities. Proved undeveloped reserves are proved reserves which are not recoverable from existing wells or facilities, but which are expected to be recovered through additional development drilling or through the upgrading of existing or additional new facilities.

5 Unproved reserves are based on geological and/or engineering data similar to that used in estimates of proved reserves, but technical, contractual, economic or regulatory uncertainties preclude such reserves being classified as proved. Unproved reserves may be further classified as probable reserves and possible reserves.

6 Proved reserves at Hibernia and Terra Nova are based on primary recovery for drilled fault blocks plus incremental recovery in fault blocks showing response to water or gas injection. Additional reserves quantities will be booked as proved reserves as development proceeds.

7 Proved reserves of synthetic crude oil from the Syncrude oil sands mining operation in northeastern Alberta are separately identified from reserves of conventional crude oil. Petro-Canada views these reserves as an integral part of the Company's business. Proved reserves of synthetic crude oil are based on high geological certainty and application of proven or piloted technology. For proved reserves, drill hole spacing is less than 500 metres and appropriate co-owner and regulatory approvals are in place.

NORTH AMERICA – CONVENTIONAL								TOTAL	
WESTERN CANADA		EAST COAST ⁸	OIL SANDS ⁹	SUBTOTAL		TOTAL CONVENTIONAL	SYNCRUDE MINING OPERATION ⁷		
Crude oil & NGL	Natural Gas	Crude oil & NGL	Bitumen	Crude oil, NGL & Bitumen	Natural Gas	Crude oil, NGL & Bitumen	Synthetic Crude oil	Crude oil & Equivalents	Natural Gas
54	2 228	42	33	129	2 228	140	310	450	2 228
3	(49)	52	–	55	(49)	103	24	127	(28)
–	(5)	–	–	–	(5)	–	–	–	(5)
–	14	–	–	–	14	328	–	328	587
5	256	–	–	5	256	15	–	15	278
(7)	(263)	(26)	(1)	(34)	(263)	(80)	(10)	(90)	(301)
55	2 181	68	32	155	2 181	506	324	830	2 759
(1)	6	35	–	34	6	72	15	87	(2)
(8)	(25)	–	–	(8)	(25)	(8)	–	(8)	(29)
–	13	–	–	–	13	3	–	3	20
1	106	–	–	1	106	1	–	1	112
(6)	(251)	(32)	(4)	(42)	(251)	(108)	(9)	(117)	(315)
41	2 030	71	28	140	2 030	466	330	796	2 545
4	224	8	33	45	224	55	108	163	224
3	205	16	17	36	205	97	147	244	502
1	82	16	17	34	82	70	165	235	272

8 Proved reserves at MacKay River are based on conservative estimates of recovery from existing producer-injector well pairs.

9 Proved reserves include quantities of crude oil and natural gas which will be produced under arrangements which involve the Company or its subsidiaries in upstream risks and rewards but do not transfer title of the product to those companies.

10 Reserves in Northwest Europe are subject to a conventional royalty and tax regime. No royalty is payable on reserves in the U.K. sector. Royalty is payable on onshore reserves in the Netherlands.

11 Reserves in Syria, Algeria and Kazakhstan are held under a production sharing arrangement with the government. The State share is split between royalty and tax for Canadian reporting purposes.

12 With the exception of the En Naga field, reserves in Libya are held under a concession and are subject to a royalty and tax regime. The En Naga field is held under a production sharing arrangement, with the government's share being split between royalty and tax for Canadian reporting purposes.

13 The volume of oil and gas reserves before royalties reported above held under production sharing contracts in the North Africa/Near East region at the end of 2003 was 112 mmbbls of crude oil and NGL and 65 bcf of natural gas. At year-end 2002 the volume was 126 mmbbls of crude oil and NGL and 77 bcf of natural gas. The after royalty reserves volumes were: year-end 2003 – 44 mmbbls of crude oil and NGL and 22 bcf of natural gas; year-end 2002 – 47 mmbbls of crude oil and NGL and 19 bcf of natural gas.

14 Crude oil reserves in Venezuela are subject to a conventional royalty and tax regime. Proved crude oil reserves in Venezuela at year-end 2003 were 0.4 million barrels before royalties (0.4 million barrels after royalties).

15 Natural gas reserves in Trinidad are held under a production sharing arrangement with the government. The State share is split between royalty and tax for Canadian reporting purposes. The volume of proved natural gas reserves before royalties reported above held under production sharing contracts in Trinidad at the end of 2003 was 324 bcf. At year-end 2002 the volume was 341 bcf. The after royalty reserves volumes were: year-end 2003 – 275 bcf; year-end 2002 – 287 bcf.

16 Revisions include changes in previous estimates, either upward or downward, resulting from new information (except an increase in acreage) normally obtained from drilling or production history or resulting from a change in economic factors.

17 Proved undeveloped conventional crude oil and natural gas liquids (NGL) reserves represent approximately 15 per cent of Petro-Canada's total conventional crude oil and NGL proved reserves. Similarly, our proved undeveloped gas reserves represent approximately 11 per cent of proved natural gas reserves. These reserves typically will be developed through tie-in of existing wells, drilling of additional wells or addition of compression facilities. Generally, we would plan to develop these reserves in the next few years.

18 Proved undeveloped reserves are a subset of proved developed and undeveloped reserves.

Petro-Canada Reserves of Crude Oil, Natural Gas Liquids, Natural Gas, Bitumen and Synthetic Crude Oil continued

(Crude oil and equivalents in millions of barrels; natural gas in billions of cubic feet)

Proved Developed and Undeveloped Reserves After Royalties ^{1,2,3,4,5}

	INTERNATIONAL							
	NORTHWEST EUROPE ¹⁰		NORTH AFRICA & NEAR EAST ^{9,11,12,13}		NORTHERN LATIN AMERICA ^{9,14,15}		SUBTOTAL	
	Crude oil & NGL	Natural Gas	Crude oil & NGL	Natural Gas	Crude oil & NGL	Natural Gas	Crude oil & NGL	Natural Gas
Beginning of year 2002	–	–	7	–	–	–	7	–
Revisions of previous estimates ¹⁶	3	11	24	3	–	–	27	14
Sale of reserves in place	–	–	–	–	–	–	–	–
Purchase of reserves in place	59	149	170	19	–	292	229	460
Discoveries, extensions and improved recovery	10	22	–	–	–	–	10	22
Production	(10)	(22)	(18)	(3)	–	(5)	(28)	(30)
End of year 2002	62	160	183	19	–	287	245	466
Revisions of previous estimates ¹⁶	14	(8)	14	5	–	6	28	3
Sale of reserves in place	–	(4)	–	–	–	–	–	(4)
Purchase of reserves in place	2	7	–	–	–	–	2	7
Discoveries, extensions and improved recovery	–	–	–	–	–	5	–	5
Production	(14)	(29)	(28)	(2)	–	(23)	(42)	(54)
End of year 2003	64	126	169	22	–	275	233	423

Proved Undeveloped Reserves After Royalties ^{17,18}

Beginning of year 2002	–	–	7	–	–	–	7	–
End of year 2002	10	22	33	–	–	232	43	254
End of year 2003	–	–	23	–	–	161	23	161

1 In order to harmonize its oil and gas disclosure in both Canada and the U.S., Petro-Canada applied for, and received, certain exemptions to reserves disclosure requirements as set out in National Instrument *NI 51-101; Standards of Disclosure for Oil and Gas Activities*. (NI 51-101). These exemptions permit Petro-Canada to use its own staff of qualified reserves evaluators to prepare the Company's reserves estimates and to use U.S. Securities and Exchange Commission (SEC) and Financial Accounting Standards Board (FASB) standards when preparing and reporting reserves. Such reserves information may differ from reserves information prepared in accordance with Canadian disclosure standards under NI 51-101. These differences relate to the SEC requirement for disclosure only of proved reserves calculated at constant year-end prices and costs while NI 51-101 requires disclosure of proved reserves at constant prices and costs and proved plus probable reserves at forecast prices and costs. Also, the definition of proved reserves differs between SEC and NI 51-101 requirements. However, this difference should not be material. The Canadian Oil and Gas Evaluation Handbook (the source document for reserves definitions under NI 51-101) supports this view.

2 Petro-Canada employs the services of independent third party evaluators/auditors to assess its reserves policies, practices and procedures and its reserves estimates.

3 Proved reserves before royalties are Petro-Canada's working interest reserves before the deduction of Crown or other royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production. No reserve quantities have been included to reflect royalty interests Petro-Canada has in various properties.

4 Proved reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those proved reserves that are expected to be recovered from existing wells or facilities. Proved undeveloped reserves are proved reserves which are not recoverable from existing wells or facilities, but which are expected to be recovered through additional development drilling or through the upgrading of existing or additional new facilities.

5 Unproved reserves are based on geological and/or engineering data similar to that used in estimates of proved reserves, but technical, contractual, economic or regulatory uncertainties preclude such reserves being classified as proved. Unproved reserves may be further classified as probable reserves and possible reserves.

6 Proved reserves at Hibernia and Terra Nova are based on primary recovery for drilled fault blocks plus incremental recovery in fault blocks showing response to water or gas injection. Additional reserves quantities will be booked as proved reserves as development proceeds.

7 Proved reserves of synthetic crude oil from the Syncrude oil sands mining operation in northeastern Alberta are separately identified from reserves of conventional crude oil. Petro-Canada views these reserves as an integral part of the Company's business. Proved reserves of synthetic crude oil are based on high geological certainty and application of proven or piloted technology. For proved reserves, drill hole spacing is less than 500 metres and appropriate co-owner and regulatory approvals are in place.

NORTH AMERICA – CONVENTIONAL								TOTAL	
WESTERN CANADA		EAST COAST*	OIL SANDS*	SUBTOTAL		TOTAL CONVENTIONAL	SYNCRUDE MINING OPERATION ⁷		
Crude oil & NGL	Natural Gas	Crude oil & NGL	Bitumen	Crude oil, NGL & Bitumen	Natural Gas	Crude oil, NGL & Bitumen	Synthetic Crude oil	Crude oil & Equivalents	Natural Gas
42	1 736	40	32	114	1 736	121	272	393	1 736
2	(62)	46	–	48	(62)	75	16	91	(48)
–	(4)	–	–	–	(4)	–	–	–	(4)
–	11	–	–	–	11	229	–	229	471
4	196	–	–	4	196	14	–	14	218
(5)	(204)	(26)	(1)	(32)	(204)	(60)	(10)	(70)	(234)
43	1 673	60	31	134	1 673	379	278	657	2 139
–	4	38	1	39	4	67	21	88	7
(7)	(19)	–	–	(7)	(19)	(7)	–	(7)	(23)
–	10	–	–	–	10	2	–	2	17
1	81	–	–	1	81	1	–	1	86
(5)	(190)	(31)	(4)	(40)	(190)	(82)	(9)	(91)	(244)
32	1 559	67	28	127	1 559	360	290	650	1 982
3	175	8	32	43	175	50	95	145	175
3	157	14	16	33	157	76	126	202	411
1	62	16	16	33	62	56	143	199	223

8 Proved reserves at MacKay River are based on conservative estimates of recovery from existing producer-injector well pairs.

9 Proved reserves include quantities of crude oil and natural gas which will be produced under arrangements which involve the Company or its subsidiaries in upstream risks and rewards but do not transfer title of the product to those companies.

10 Reserves in Northwest Europe are subject to a conventional royalty and tax regime. No royalty is payable on reserves in the U.K. sector. Royalty is payable on onshore reserves in the Netherlands.

11 Reserves in Syria, Algeria and Kazakhstan are held under a production sharing arrangement with the government. The State share is split between royalty and tax for Canadian reporting purposes.

12 With the exception of the En Naga field, reserves in Libya are held under a concession and are subject to a royalty and tax regime. The En Naga field is held under a production sharing arrangement, with the government's share being split between royalty and tax for Canadian reporting purposes.

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Principal Reserves and Production Locations

Crude Oil Fields ²	Proved Reserves ¹ Before Royalties at December 31, 2003 (millions of barrels)	Per cent of Total Proved Oil Reserves	Average 2003 Daily Production ¹ Before Royalties (thousands of barrels)	Per cent of Total 2003 Daily Oil Production
Syncrude, Alberta	330	43	25	8
Ghani/Zenad Farud, Libya	49	6	15	5
Amal, Libya	48	6	15	5
Terra Nova, Newfoundland and Labrador – Offshore	37	5	46	15
Hibernia, Newfoundland and Labrador – Offshore	34	4	41	14
MacKay River, Alberta	28	4	11	4
Ghani Gir/Facha, Libya	20	3	4	1
Guillemot West, U.K. – Offshore	20	3	12	4
Omar, Syria	15	2	13	4
Scott, U.K. – Offshore	14	2	5	2
Other	168	22	116	38
Total	763	100	303	100

Natural Gas Fields ²	Proved Reserves ¹ Before Royalties at December 31, 2003 (billions of cubic feet)	Per cent of Total Proved Gas Reserves	Average 2003 Daily Production ¹ Before Royalties (millions of cubic feet)	Per cent of Total 2003 Daily Gas Production
Wildcat Hills area, Alberta	524	21	154	18
NCMA-1, Trinidad – Offshore	324	13	63	7
Hanlan area, Alberta	316	12	102	12
Jedney/Beg/Bubbles, British Columbia	212	8	38	4
Medicine Hat, Alberta	163	6	38	4
Ricinus/Bearberry area, Alberta	154	6	85	10
Laprise area, British Columbia	107	4	34	4
Alderson, Alberta	80	3	22	3
Ferrier, Alberta	78	3	19	2
Gilby/Wilson Creek, Alberta	70	3	29	3
Other	517	21	284	33
Total	2 545	100	868	100

1 Does not include natural gas liquids. Total Corporate reserves of crude oil and equivalents at year-end 2003 were 796 million barrels.

2 Fields are onshore unless otherwise indicated.

Oil and Gas Landholdings

(Gross ¹ /Net ²) (millions of acres)	Developed ³		Undeveloped ⁴		Total		Land Expiries in 2004	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Mainland Canada ⁵	2.05	1.03	4.19	2.95	6.24	3.98	1.18	0.75
Oil Sands	0.20	0.08	0.42	0.20	0.62	0.28	0.16	0.08
East Coast Offshore	0.09	0.02	4.24	1.50	4.33	1.52	0.80	0.21
Other Frontier Canada	0.00	0.00	7.67	6.19	7.67	6.19	0.00	0.00
Alaska	0.00	0.00	0.41	0.41	0.41	0.41	0.00	0.00
Total North America	2.34	1.13	16.93	11.25	19.27	12.38	2.14	1.04
Northwest Europe	0.17	0.08	2.00	0.58	2.17	0.66	0.00	0.00
North Africa/Near East	0.91	0.39	9.15	6.09	10.06	6.48	0.00	0.00
Northern Latin America	0.05	0.01	0.19	0.07	0.24	0.08	0.00	0.00
Total International	1.13	0.48	11.34	6.74	12.47	7.22	0.00	0.00
Total	3.47	1.61	28.27	17.99	31.74	19.60	2.14	1.04

1 Includes interests of others.

2 Excludes interests of others.

3 Areas capable of production.

4 Areas with rights to explore.

5 Includes Mackenzie Delta/Corridor.

Quarterly Financial and Stock Trading Information

(unaudited, stated in millions of dollars unless otherwise indicated)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter 2003	First Quarter	Second Quarter	Third Quarter	Fourth Quarter 2002
Revenue								
Operating	\$ 3 522	\$ 2 773	\$ 2 983	\$ 2 931	\$ 1 701	\$ 2 441	\$ 2 773	\$ 3 002
Investment and other income	(15)	53	(24)	(2)	7	(4)	(6)	3
	3 507	2 826	2 959	2 929	1 708	2 437	2 767	3 005
Expenses								
Crude oil and product purchases	1 465	1 136	1 227	1 270	885	1 107	1 298	1 266
Operating, marketing and general	577	575	637	618	397	494	528	617
Exploration	121	59	53	38	106	44	79	72
Depreciation, depletion and amortization	343	293	444	459	162	240	276	279
Foreign currency translation	(97)	(99)	(5)	(50)	1	(47)	82	16
Interest	48	45	46	43	30	45	56	56
	2 457	2 009	2 402	2 378	1 581	1 883	2 319	2 306
Earnings Before Income Taxes	1 050	817	557	551	127	554	448	699
Provision for Income Taxes	467	232	256	351	39	233	239	343
Net Earnings	\$ 583	\$ 585	\$ 301	\$ 200	\$ 88	\$ 321	\$ 209	\$ 356
Cash Flow								
	\$ 991	\$ 874	\$ 879	\$ 628	\$ 287	\$ 540	\$ 642	\$ 807
Earnings								
Upstream								
North American Gas	\$ 166	\$ 144	\$ 103	\$ 66	\$ 2	\$ 57	\$ 31	\$ 90
East Coast Oil	162	155	139	137	65	116	112	137
Oil Sands	13	11	20	(94)	6	1	51	21
International	64	70	113	50	(6)	58	78	95
Downstream	130	127	(27)	34	45	73	58	78
Shared Services	(46)	(55)	(40)	(41)	(23)	(29)	(41)	(51)
Earnings from operations	489	452	308	152	89	276	289	370
Foreign currency translation	94	98	4	43	(1)	45	(80)	(16)
Gain (loss) on sale of assets	–	35	(11)	5	–	–	–	2
Net earnings	\$ 583	\$ 585	\$ 301	\$ 200	\$ 88	\$ 321	\$ 209	\$ 356
Share Information (dollars per share)								
Earnings								
– Basic	\$ 2.21	\$ 2.21	\$ 1.13	\$ 0.75	\$ 0.34	\$ 1.22	\$ 0.79	\$ 1.35
– Diluted	2.18	2.18	1.12	0.75	0.33	1.21	0.79	1.34
Cash flow	3.75	3.30	3.31	2.37	1.09	2.06	2.44	3.06
Dividends per share	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Share price ¹								
– High	54.01	56.31	56.54	64.55	42.05	44.48	48.85	50.15
– Low	47.40	45.75	51.75	51.96	33.90	39.33	36.89	42.90
– Close (end of period)	\$ 50.00	\$ 53.96	\$ 52.49	\$ 63.91	\$ 41.06	\$ 42.75	\$ 46.56	\$ 48.91
Shares traded (millions) ²	50.6	49.6	32.0	37.8	63.9	37.5	49.8	45.2

¹ Share prices are for trading on the Toronto Stock Exchange.

² Total shares traded on the Toronto and New York stock exchanges.

Three-Year Financial and Operating Summary

(stated in millions of dollars, unless otherwise indicated)

Starting with this report, Petro-Canada is disclosing all Upstream business segments on a separate basis. This year's table is a three-year summary, instead of the previous years' five-year summary, due to the comparability and availability of the data for the three Upstream segments that have not been previously disclosed on a separate basis.

	2003	2002	2001
Consolidated			
Revenue	\$ 12 221	\$ 9 917	\$ 8 736
Expenses	9 246	8 089	7 407
Provision for income taxes	1 306	854	483
Net Earnings	\$ 1 669	\$ 974	\$ 846
Cash flow	3 372	2 276	1 688
Total assets	14 590	13 439	9 634
Average capital employed	9 392	7 826	6 259
Operating return on capital employed (per cent) ¹	16.1	14.5	15.8
Return on capital employed (per cent)	18.9	13.9	14.8
Debt	2 229	3 057	1 401
Debt to debt plus equity (per cent)	22.4	34.6	22.3
Debt to cash flow (times)	0.7	1.3	0.8
Expenditures on property, plant and equipment and exploration	2 315	1 861	1 681
Employees (number at year end)	4 514	4 470	4 178
Shareholders' Data			
Weighted average number of common shares outstanding (millions)	264.9	262.8	264.9
Shares outstanding at year end (millions) ²	265.6	263.6	262.2
Publicly held shares at year end (millions)	216.2	214.2	212.8
Share prices (dollars) ³			
– at year end	63.91	48.91	39.31
– range during the year	45.75-64.55	33.90-50.15	33.50-43.65
Shares traded (millions) ⁴	169.9	196.4	212.0
Book value per share (dollars)	29.07	21.91	18.60

1 Earnings from operations are earnings before gains or losses on foreign currency translation and on disposal of assets.

2 Includes 49.4 million shares held as an investment by the Government of Canada.

3 Year-end prices and ranges are from the Toronto Stock Exchange.

4 Total shares traded on the Toronto and New York stock exchanges.

	2003	2002	2001
North American Gas			
Earnings from operations	\$ 479	\$ 180	\$ 463
Gain (loss) on sale of assets	33	(1)	29
Net earnings	\$ 512	\$ 179	\$ 492
Cash flow	985	534	651
Expenditure on property, plant and equipment and exploration	560	530	548
Daily production (before/after royalties)			
Crude oil and liquids (thousands of barrels)	16.9/12.6	18.9/14.2	18.6/13.8
Natural gas (millions of cubic feet)	693/521	722/557	714/533
Proved reserves (before/after royalties)			
Crude oil and liquids (millions of barrels)	41/32	55/43	54/42
Natural gas (billions of cubic feet)	2 030/1 559	2 181/1 673	2 228/1 736
Oil and gas landholdings (gross/net) (millions of acres)	14.3/10.6	14.0/10.4	13.9/10.0
Wells drilled (gross/net)			
Oil	9/2	4/4	13/11
Natural gas	412/248	348/203	354/229
Dry	37/30	29/20	27/16
Suspended	1/1	0/0	0/0
Total	459/281	381/227	394/256

	2003	2002	2001
East Coast Oil			
Earnings from operations and net earnings	\$ 593	\$ 430	\$ 168
Cash flow	869	687	338
Expenditure on property, plant and equipment and exploration	344	289	279
Daily production <i>(before/after royalties)</i>			
Crude oil and liquids <i>(thousands of barrels)</i>	86.1/84.0	71.9/70.9	29.7/29.2
Proved reserves <i>(before/after royalties)</i>			
Crude oil and liquids <i>(millions of barrels)</i>	71/67	68/60	42/40
Oil and gas landholdings <i>(gross/net) (millions of acres)</i>	4.3/1.5	5.1/1.7	6.4/2.4
Wells drilled <i>(gross/net)</i>			
Oil	12/3	13/3	14/4
Dry	3/1	3/1	0/0
Total	15/4	16/4	14/4
Oil Sands			
Earnings (loss) from operations and net earnings (loss)	\$ (50)	\$ 79	\$ 59
Cash flow	127	196	136
Expenditure on property, plant and equipment and exploration	448	462	304
Daily production <i>(before/after royalties)</i>			
Bitumen <i>(thousands of barrels)</i>	10.7/10.6	1.1/1.0	0/0
Synthetic Crude Oil <i>(thousands of barrels)</i>	25.4/25.1	27.5/27.2	26.8/24.8
Proved reserves <i>(before/after royalties)</i>			
Bitumen <i>(millions of barrels)</i>	28/28	32/31	33/32
Synthetic Crude Oil <i>(millions of barrels)</i>	330/290	324/278	310/272
Oil and gas landholdings <i>(gross/net) (millions of acres)</i>	0.6/0.3	0.9/0.3	0.8/0.3
Wells drilled <i>(gross/net)</i>			
Oil Sands – Bitumen	0/0	0/0	50/50
Dry	0/0	0/0	0/0
Total	0/0	0/0	50/50
International			
Earnings (loss) from operations	\$ 297	\$ 225	\$ (27)
Gain on sale of assets	10	–	–
Net earnings (loss)	\$ 307	\$ 225	\$ (27)
Cash flow	890	583	27
Expenditures on property, plant and equipment and exploration	525	221	153
Daily production <i>(before/after royalties)</i>			
Crude oil and liquids <i>(thousands of barrels)</i>	180.8/115.6	125.5/75.2	2.3/1.5
Natural gas <i>(millions of cubic feet)</i>	175/149	103/81	0/0
Proved reserves <i>(before/after royalties)</i>			
Crude oil and liquids <i>(millions of barrels)</i>	326/233	351/245	11/7
Natural gas <i>(billions of cubic feet)</i>	515/423	578/466	0/0
Oil and gas landholdings <i>(gross/net) (millions of acres)</i>	12.5/7.2	12.9/7.2	5.7/5.7
Wells drilled <i>(gross/net)</i>			
Oil	54/21	39/17	3/1
Natural gas	6/1	5/1	0/0
Dry	12/6	9/4	0/0
Total	72/28	53/22	3/1
Downstream			
Earnings from operations	\$ 264	\$ 254	\$ 300
(Loss) gain on sale of assets	(15)	3	1
Net earnings	\$ 249	\$ 257	\$ 301
Cash flow	601	380	589
Expenditures on property, plant and equipment	424	344	383
Petroleum product sales <i>(thousands of cubic metres per day)</i>	56.8	55.7	54.5
Retail outlets at year end	1 432	1 537	1 566
Refinery crude capacity at year end <i>(thousands of cubic metres per day)</i>	49.8	49.8	49.8
Average refinery utilization <i>(per cent)</i>	100	101	96

EXECUTIVE LEADERSHIP TEAM*

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President and
Chief Executive Officer

Peter Kallos
Executive Vice-President,
International

Boris Jackman
Executive Vice-President,
Downstream

Harry Roberts
Senior Vice-President and
Chief Financial Officer

Kathy Sendall
Senior Vice-President,
North American Natural Gas

Brant Sangster
Senior Vice-President,
Oil Sands

Gordon Carrick
Vice-President, East Coast

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Chief Executive Officer
Petro-Canada

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Corporate Director

William W. Siebens
President and
Chief Executive Officer
Candor Investments Ltd.

SECRETARY TO THE BOARD OF DIRECTORS

W.A. (Alf) Peneycad
Vice-President,
General Counsel,
Corporate Secretary and
Chief Compliance Officer
Petro-Canada

* As of March 4, 2004.

¹ Chief Executive Officer until February 15, 2004 when appointed President and Chief Executive Officer. Norm McIntyre retired as President on February 15, 2004.

Please see the Management Proxy Circular for additional information about Petro-Canada's Senior Officers, Board of Directors and governance practices. The Management Proxy Circular contains: disclosure on executive compensation and contracts; mandates and reports of Board committees; a Statement of Corporate Governance Practices; and detail on Directors' business background, tenure, committee membership, remuneration and share ownership. The Management Proxy Circular is available for viewing on our Web site at www.petro-canada.ca or by contacting Investor Relations.

INVESTOR INFORMATION

Outstanding Shares

At December 31, 2003, Petro-Canada's public float was 216.2 million shares.

Transfer Agent and Registrar

In Canada:

CIBC Mellon Trust Company

In the United States:

Mellon Investor Services, LLC

Telephone toll free: 1-800-387-0825

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Web site: www.cibcmellon.com

Duplicate Reports

Shareholders with more than one unregistered account may receive duplicate materials. To eliminate duplicate mailings, contact your broker.

Registered shareholders may contact the transfer agent and registrar.

Annual and Special Meeting

The annual and special meeting of shareholders will be held at 11:00 a.m. local time Tuesday, April 27, 2004, The Fairmont Palliser Hotel, Crystal Ballroom, 133-9th Avenue S.W., Calgary, Alberta.

Stock Exchange Listings and Symbols

Toronto: PCA

New York: PCZ

Dividends

Petro-Canada's Board of Directors has adopted a policy of paying quarterly dividends of \$0.15 (\$0.60 per annum) per common share. The Board regularly reviews the dividend policy in light of the Company's financial position, its financing requirements for growth, and other factors.

On Our Web Site...

Petro-Canada's Web site, www.petro-canada.ca, contains a variety of corporate and investor information, including:

- Statistical Supplement
- Annual Information Form
- Quarterly Reports
- Management Proxy Circular
- Presentations and Webcasts
- Dividend History
- Petro-Canada's Code of Business Conduct
- Petro-Canada's Principles for Investment and Operations
- Report to the Community

Investor Relations

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Corporate Communications

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Web site: www.petro-canada.ca

We'd Like Your Feedback

We invite your comments on our low-cost annual report format. Please e-mail your comments to: sbraunga@petro-canada.ca

Glossary of Financial Terms and Ratios

Terms

BARREL OF OIL EQUIVALENT:

Natural gas production (excluding injectants) is converted using 6 000 cubic feet of gas for one barrel of oil.

CAPITAL EMPLOYED:

Total of shareholders' equity and debt.

CASH FLOW:

Cash flow from operations before changes in non-cash working capital items.

DEBT:

Long-term debt including current portion.

EARNINGS FROM OPERATIONS:

Earnings before gains or losses on foreign currency translation and on asset sales.

Ratios

RETURN ON CAPITAL EMPLOYED:

Net earnings plus after-tax interest expense divided by average capital employed. Measures net earnings relative to the capital employed in the Company.

OPERATING RETURN ON CAPITAL EMPLOYED:

Earnings from operations plus after-tax interest expense divided by average capital employed.

CASH FLOW RETURN ON CAPITAL EMPLOYED:

Cash flow plus after-tax interest expense divided by average capital employed. Measures cash flow generated relative to the asset base.

RETURN ON EQUITY:

Net earnings divided by average shareholders' equity. Measures the return earned by shareholders on their investment in the Company.

DEBT TO CASH FLOW:

Debt divided by cash flow. Indicates the Company's ability to discharge its outstanding debt.

DEBT TO DEBT PLUS EQUITY:

Debt divided by debt plus equity. Indicates the relative amount of debt in the Company's capital structure. Measures financial strength.

INTEREST COVERAGE:

Measures the Company's ability to cover interest charges on debt.

Earnings basis: Earnings before interest expense and provision for income taxes divided by interest expense plus capitalized interest.

EBITDAX basis: Earnings before interest expense, income taxes, depreciation, depletion and amortization and exploration expenses divided by interest expense plus capitalized interest.

Cash flow basis: Cash flow before interest expense and current income taxes divided by interest expense plus capitalized interest.

Conversion Factors

To conform with common usage, imperial units of measurement are used in this report to describe exploration and production, while metric units are used for refining and marketing. Dollars are Canadian unless otherwise stated.

1 cubic metre (liquids) = 6.29 barrels

1 cubic metre (natural gas) =
35.30 cubic feet

1 litre = 0.22 imperial gallon

1 hectare = 2.47 acres

1 cubic metre = 1 000 litres

A VERY CAPABLE COMPANY

Petro-Canada is focused and disciplined, with the financial and human capability to execute our strategy.

A HIGHLY PRINCIPLED COMPANY

We consider high standards of honesty, integrity and ethical behaviour as key to our success, and apply these standards wherever we operate.

BUILDING A TRACK RECORD OF SUCCESS

Our plans for continued profitability improvement and growth position us to extend our record of building shareholder value.

POSITIONED FOR A WORLD-CLASS FUTURE

We are disciplined in where and how we invest, selecting the best from our extensive portfolio of world-class opportunities.

